FORM 10-K

Annual report pursuant to section 13 and 15(d)

Filing Date: **1999-03-26** | Period of Report: **1998-12-31**
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FILER

UTILICORP UNITED INC

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SIC: **4931** Electric & other services combined

Mailing Address
PO BOX 13287
KANSAS CITY MO 64199-3287

Business Address
20 WEST NINTH STREET
911 MAIN STE 3000
KANSAS CITY MO 64105-1711
8164216600

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

<TABLE>

<C>	<S>
(MARK ONE) /X/	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [FEE REQUIRED]
	FOR THE FISCAL YEAR ENDED DECEMBER 31, 1998
	OR
/ /	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]

</TABLE>

FOR THE TRANSITION PERIOD FROM   TO

COMMISSION FILE NUMBER: 1-3562

UTILICORP UNITED INC.

(Exact name of registrant as specified in its charter)

<TABLE>

<S>	<C>
DELAWARE	44-0541877
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)

</TABLE>

20 West Ninth Street, Kansas City, Missouri 64105
(Address of principal executive offices)

REGISTRANT'S TELEPHONE NUMBER, INCLUDING AREA CODE (816) 421-6600

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) of the Act:

<TABLE>
<CAPTION>

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
<S>	<C>
Common Stock, par value $1.00 per share	New York, Pacific and Toronto Stock Exchanges
Convertible Subordinated Debentures, 6-5/8%, due July 1, 2011	New York Stock Exchange
8-7/8% Cumulative Monthly Income Preferred Securities, Series A, due June 12, 2025	New York Stock Exchange

</TABLE>

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. / /

The aggregate market value of the voting stock held by non-affiliates of the Registrant, based upon the closing sale price of the Common Stock on March 15, 1999 as reported on the New York Stock Exchange, was approximately $2,132,635,622. Shares of Common Stock held by each officer and director and by each person who owns 5% or more of the outstanding Common Stock have been excluded in that such persons may be deemed to be affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

<TABLE>
<CAPTION>

TITLE	OUTSTANDING (AT MARCH 15, 1999)
Common Stock, par value $1.00 per share	93,605,985

Documents Incorporated by Reference:	Where Incorporated:
1998 Annual Report to Shareholders	Part 2
Proxy Statement for 1999 Annual Shareholders Meeting	Part 3

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PART 1

ITEM 1. BUSINESS.

ORGANIZATION AND HISTORY

UtiliCorp United Inc. (the company, which may be referred to as we, us, or our) is a multinational energy solutions provider. We conduct business through the following business segments:

- REGULATED BUSINESSES--includes our domestic utility generation, distribution and transmission businesses. Regulated businesses also includes appliance repair/servicing and limited gas marketing businesses.

- AQUILA ENERGY--includes our natural gas and electricity marketing and trading businesses, and Aquila Gas Pipeline Corporation, a publicly traded natural gas gathering, processing and transportation company.

- INTERNATIONAL--includes our investments in an electric distribution company in Australia, 79% owned UnitedNetworks Limited, (an electric transmission company) in New Zealand, a gas transportation and risk merchant company in the United Kingdom and an electric utility in Canada.

OUR STRATEGY

Our strategy is to operate energy delivery networks and to be a leading energy merchant in the markets in which we compete. We believe this strategic focus positions us to compete effectively in a deregulated energy marketplace.

The key elements of our strategy include:

- ALIGNMENT OF BUSINESSES TO ADDRESS A CHANGING COMPETITIVE ENVIRONMENT. We believe that our distinct, yet inter-related, business groups enable us to better manage our operations in the changing marketplace in which we operate. Our corporate structure allows us to manage each of these businesses individually, improving our ability to maximize their profitability while providing low cost, high quality energy and energy related products and services to our customers.

- PURSUIT OF STRATEGIC MERGERS, ACQUISITIONS, ALLIANCES, JOINT VENTURES AND PARTNERSHIPS. Growth through mergers and acquisitions has been a major part of our strategy for more than a decade. We believe that our approximately $2.7 billion of investments in mergers and acquisitions has played an integral role in establishing us as a leading diversified energy provider. Most recently, we have completed several transactions to enhance our operations in New Zealand and on March 11, 1999 submitted a winning bid for a gas utility in Australia.

- IMPROVE OPERATIONAL EXCELLENCE. We constantly seek to improve our operational performance. Over the last several years we have consolidated operations of our domestic electric and natural gas distribution businesses. As an example, our Regulated Businesses group is implementing a single billing and accounting system for all of our domestic regulated utilities in eight states. We have reduced the number of field offices from 129 to 57, resulting in the elimination of 380 positions. We have developed an energy marketing, trading and risk management system at Aquila that will support substantially greater marketing and trading volumes without the need for material additional investment.

- FOCUSED INTERNATIONAL OPERATIONS. Our International group is focused on seeking early entry into markets that provide a combination of stable and attractive political and economic environments and markets open or opening to competition in electric or natural gas sales. As an example, we were the first non-Australian company to invest in and manage an Australian electric distribution company. As owners and managers of our international operations, we seek to

transfer our domestic knowledge and skills to improve the performance of those operations. At the same time, we benefit from experience gained in new, competitive international marketplaces, and we are using the knowledge gained overseas to better position ourselves for domestic deregulation.

- RISK MANAGEMENT. In order to compete effectively and profitably in energy marketing and trading, we have an independent trading control officer who reports directly to our President and also reports independently to the Board of Directors. We closely monitor our operations and have written policies and established trading limits. We have developed proprietary risk management software which we license to other companies.

OUR COMPETITIVE STRENGTHS

We believe that we have developed substantial competitive strengths that will enable us to continue to successfully execute our strategy. These strengths include:

- Low cost, non-nuclear electric and natural gas utility businesses focused on superior customer service.

- Market-leading position in energy marketing and trading.

- Experienced management team whose compensation is directly tied to shareholder value.

- Proven risk management policies and procedures to limit exposure to commodity market positions.

- Successful operation of competitive non-regulated businesses

- International operations in New Zealand, Australia, the United Kingdom, and Canada from which we believe we have gained valuable experience in competitive markets.

- Proven track record of quickly and successfully integrating domestic and international mergers and acquisitions.

MERGERS & ACQUISITIONS

ST. JOSEPH LIGHT & POWER

In March 1999, we signed a definitive agreement with St. Joseph Light & Power Company to merge in a transaction valued at approximately $270 million. The agreement is subject to approvals by St. Joseph shareholders, and by state and federal regulatory agencies. The merger is expected to be completed sometime in mid-2000.

MULTINET GAS/IKON ENERGY

In March 1999, we and an Australian partner made a successful bid of $1.26 billion to acquire the natural gas utility Multinet Gas/Ikon Energy from the State of Victoria, Australia. The acquisition is expected to be completed by April 1999, with our ownership interest at 25.5%.

BUSINESS GROUP SUMMARY

Segment information for the three years ended December 31, 1998 is incorporated by reference to pages 56 through 58 of our 1998 Annual Report to Shareholders.

I. REGULATED BUSINESSES

ELECTRIC OPERATING STATISTICS

The following table summarizes Regulated Businesses' sales, volumes and customers for electric generation, transmission and distribution businesses.

	1998	1997	1996	1995	1994	1998-1994 CAGR*
Sales (in millions)						
Residential	$ 244.8	$ 232.1	$ 227.3	$ 219.5	$ 211.4	3.7%
Commercial	161.3	154.5	147.3	142.0	140.7	3.5%
Industrial	74.8	73.6	70.4	67.9	66.4	3.0%
Other	46.7	97.2	74.3	60.7	57.6	(5.1)%
Total	$ 527.6	$ 557.4	$ 519.3	$ 490.1	$ 476.1	2.6%
Volumes (Gigawatt Hours (GWH)-000's)						
Residential	3,169	2,942	2,897	2,758	2,639	4.7%
Commercial	2,585	2,409	2,308	2,236	2,190	4.2%
Industrial	1,779	1,727	1,660	1,608	1,535	3.8%
Other	905	1,390	1,939	1,372	1,230	(7.4)%
Total	8,438	8,468	8,804	7,974	7,594	2.7%
Customers						
Residential	320,740	313,598	308,271	302,857	297,801	1.9%
Commercial	48,800	48,012	46,651	47,378	46,470	1.2%
Industrial	305	290	286	288	285	1.7%
Other	3,560	3,590	3,606	3,556	3,545	.1%
Total	373,405	365,490	358,814	354,079	348,101	1.8%

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* Compound annual growth rate

GAS OPERATING STATISTICS

The following table summarizes Regulated Businesses' sales, volumes and customers for gas distribution businesses.

	1998	1997	1996	1995	1994	1998-1994 CAGR*
Sales (in millions)						
Residential	$ 379.4	$ 464.4	$ 429.1	$ 362.2	$ 356.4	1.6%
Commercial	161.2	205.8	192.6	153.9	156.9	.7%
Industrial	34.1	46.8	45.8	45.8	66.7	(15.4)%
Other	47.7	50.4	60.4	54.9	38.6	5.4%
Total	$ 622.4	$ 767.4	$ 727.9	$ 616.8	$ 618.6	.2%
Volumes--(Thousand Cubic Feet (MCF)-000's)						

Residential	66,564	77,594	81,698	76,461	71,208	(1.7)%
Commercial	33,228	39,128	40,698	37,282	35,952	(2.0)%
Industrial	8,631	11,059	10,944	12,901	18,439	(17.3)%
Transportation	140,499	158,937	166,562	178,114	135,924	.8%
Other	1,088	678	1,611	1,827	2,420	(18.1)%
Total	250,010	287,396	301,513	306,585	263,943	(1.3)%
Customers						
Residential	761,650	744,238	728,867	713,586	698,156	2.2%
Commercial	77,971	78,925	77,742	76,430	76,015	.6%
Industrial	1,982	2,491	3,725	3,790	3,878	(15.4)%
Other	9,986	2,491	2,573	2,815	1,581	58.5%
Total	851,589	828,145	812,907	796,621	779,630	2.2%

</TABLE>

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*   Compound annual growth rate

REGULATION

The following is a summary of our pending rate case activity.

<TABLE>
<CAPTION>

RATE CASE DESIGNATION (IN MILLIONS)	TYPE OF SERVICE	DATE REQUESTED	AMOUNT REQUESTED
<S>	<C>	<C>	<C>
West Virginia	Gas	10/30/98	$ 2.9
West Virginia	Electric	12/15/98	$ 4.7

</TABLE>

In April 1998, we were ordered to reduce Missouri electric rates by $16.9 million plus increase depreciation expense by $5.8 million. This rate reduction lowered 1998 EBIT by $16.3 million.

ENVIRONMENTAL

We are subject to various environmental laws. These include regulations governing air and water quality and the storage and disposal of hazardous or toxic wastes. We continually assess ways to ensure we comply with laws and regulations on hazardous materials and hazardous waste and remediation activities.

We own or previously operated 29 former manufactured gas plants (MGP's) which may, or may not, require some form of environmental remediation. We have contacted appropriate federal and state agencies and are working to determine what, if any, specific cleanup activities these sites may require.

As of December 31, 1998, we estimate cleanup costs on our identified MGP sites to be $10.0 million. This estimate could change materially when we have investigated further. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties. Ultimate liability also may be affected significantly if we are held responsible for parties unable to contribute financially to the cleanup effort.

We have received favorable rate orders that enable us to recover environmental cleanup costs in certain jurisdictions. In other jurisdictions, there are favorable regulatory precedents for recovery of these costs. We are also pursuing recovery from insurance carriers and other potentially responsible parties.

In December 1996, the U.S. Environmental Protection Agency (EPA) published its final rule for nitrous oxide (NOx) emissions as required by the Clean Air Act Amendments of 1990. The new NOx regulations require that we install additional emissions control equipment at one of our power plants by January 1, 2000.

In October 1998, the EPA published new air quality standards to further reduce the emission of NOx. These more strict standards will require us to install new equipment on our baseload coal units in Missouri that we estimate will cost $35 million. The ultimate cost is under debate and subject to change. The new standards as written are effective in May 2003.

We do not expect final resolution of these environmental matters to have a material adverse effect on our financial position or results of operations.

SEASONAL VARIATIONS OF BUSINESS

Our utility and independent power project businesses are weather-sensitive. We have both summer and winter peaking utility assets to reduce dependence on a single peak season. The table below shows peak times for our utility businesses.

JURISDICTION	PEAK
Gas utility operations	November through March
Missouri, Kansas and Colorado electric	July and August
West Virginia electric	November through March

II. AQUILA ENERGY

WHOLESALE ENERGY MARKETING

Aquila's wholesale energy marketing business is conducted through various operating units, collectively referred to as Energy Marketing. Energy Marketing is a gas and power marketing company with a marketing, supply and transportation network consisting of relations with gas producers, local distribution companies, and end-users throughout the United States and Canada. Energy Marketing adds value for customers by leveraging its national position in financial deal structuring in gas and power marketing. It provides services such as complex fuel supply arrangements, energy management services and project development focused on control of mid-stream energy assets. For the five years ended December 31, 1998, Energy Marketing had marketing volumes of 9.6, 6.8, 3.5, 1.9, and 1.4 billion cubic feet a day (BCF/d), respectively.

In 1995, Energy Marketing began selling electricity to wholesale customers, much as it markets natural gas. Aquila expects that the electricity marketing industry will continue to expand rapidly as

liquidity and maturity increases. Aquila's wholesale power sales have grown from 129,000 megawatt hours (MWH) in 1995 to 121.2 million MWH in 1998, ranking it third among the nation's largest volume power marketers.

Energy Marketing utilizes certain types of fixed-price contracts in connection with its natural gas and power marketing businesses. These include contracts that commit us to purchase or sell natural gas and other commodities at fixed prices in the future (i.e., fixed-price forward purchase and sales contracts), futures and options contracts traded on the NYMEX and swaps and other types of financial instruments traded in the over-the-counter financial markets.

The availability and use of these types of contracts allows us to manage and hedge our contractual commitments, reduce our exposure relative to the volatility of cash market prices, take advantage of carefully selected arbitrage opportunities via open positions, protect our investment in natural gas storage inventories and provide price risk management services to our customers. We are also able to secure additional sources of energy or create additional markets for existing supply through the use of exchange for physical transactions allowed by NYMEX. We refer to our domestic and Canadian natural gas and electricity trading activities as price risk management activities. These are reflected in the accompanying financial statements using the mark-to-market method of accounting.

Although we generally attempt to balance our fixed-price physical and financial purchase and sales contracts in terms of contract volumes and the timing of performance and delivery obligations, net open positions often exist or are established due to the origination of new transactions and our assessment of, and response to, changing market conditions. We will occasionally create a net open position or allow a net open position to continue when we believe, based upon competitive information gained from our energy marketing activities, that future price movements will be consistent with our net open position. When we have a net open position, we are exposed to fluctuating market prices.

In addition to price risk movements, credit risk is also inherent in our risk management activities. Our trading and marketing business is also exposed to counterparty credit risk resulting from a counterparty not fulfilling its contractual obligations. Our credit policies with regard to our counterparties attempt to minimize overall credit risk. Our credit procedures include a thorough review of potential counterparties' financial condition, collateral requirements under certain circumstances, monitoring of net exposure to each counterparty and the use of standardized agreements which allow for the netting of positive and negative exposures associated with each counterparty. Our credit policy is monitored and administered by a function independent of the trading and marketing activities.

GAS GATHERING AND PROCESSING

Aquila Gas Pipeline (AQP) gathers and processes natural gas and natural gas liquids. AQP owns and operates a 3,403-mile intrastate gas transmission and gathering network and four processing plants that extract and sell natural gas liquids.

Key operating statistics for AQP are presented in the table below.

<TABLE>
<CAPTION>

	1998	1997	1996	1995	1994
<S>	<C>	<C>	<C>	<C>	<C>
Natural gas throughput (million cubic feet per day(MMcf/d))..........	475	483	493	506	371
Natural gas liquids produced (thousand barrels per day)..............	25	37	41	32	31
Pipeline miles owned...	3,403	3,434	3,416	3,311	2,718

</TABLE>

Aquila Energy and AQP own 35% of the capital stock of Oasis Pipe Line Company (Oasis) and have 280 MMcf/d of firm intrastate transportation capacity. The 600-mile Oasis pipeline system spans the state of Texas and links Aquila's gathering systems to the Waha, Texas hub and the Katy, Texas hub.

In 1998, AQP entered into a joint venture ownership and operation agreement with a third party in the Austin Chalk area in Texas to gather and transport the natural gas produced from specified wells. The sales contract accounted for approximately 2% of AQP's total natural gas sales in 1998.

In November 1998, we made a proposal to acquire the 18% of AQP's common stock we do not already own for $8.00 per share. An independent committee of AQP's Board of Directors is evaluating the proposal.

INDEPENDENT POWER PROJECTS

Aquila Energy participates in the ownership and operation of facilities in the independent and wholesale power generation market. Consistent with the company's overall strategy to minimize risk through diversification, Aquila Energy has invested in generation facilities which are geographically diverse and use a variety of fuels and proven technologies. Additionally, each project is a producer of competitively priced wholesale power in its geographic region and has a long-term market for its output. To date, Aquila Energy has made investments in 17 projects located in seven states and Jamaica, with a total net ownership of approximately 332 MW of generating capacity. A description and listing of the power projects appears on page X of this report.

We anticipate further expansion or investment in the independent power projects business through a newly formed entity focused on structuring and obtaining control of mid-stream energy assets.

III. INTERNATIONAL

Our international operations are managed separately from the other two business groups. However, these energy operations are consistent with either the delivery network or energy merchant strategies. We manage our international businesses with local management that reports separately to the company. The normalized contribution to earnings before interest and taxes from international businesses was 20.8%, 17.0%, and 25.2% of our total for the years ended December 31, 1998, 1997 and 1996, respectively. As of December 31, 1998, approximately $1,655.0 million of our total assets relate to our international businesses. The following discussion briefly describes our international businesses.

AUSTRALIA

We acquired an effective 49.9% ownership interest in United Energy Limited (UEL), an electric distribution utility serving 546,000 customers in the state of Victoria. As part of a management agreement between us and UEL, we manage the utility for a fee as well as participate in its earnings.

In May 1998, UEL sold 42% of its common stock to the Australian public and as a result, we recorded a $45.3 million gain. The partial sale to the public reduced our effective ownership percentage to 29%. Concurrent with UEL's stock offering, we bought an additional 5% in UEL from another company to bring our ownership to 34%. Prior to the common stock sale, UEL repaid approximately $101 million in debt notes owed to us. The management agreement between us and UEL remains in place.

UEL distributes and sells electricity with a majority of its sales earned from the regulated distribution network business. The regulated distribution sales and connection charges for access to its distribution system will be reviewed by the Office of the Regulator General (OGR), with new rates becoming effective for five years beginning January 1, 2001.

The retail market in which UEL operates is being progressively opened to competition, with all customers becoming contestable by January 1, 2001. The following table shows the timing of electricity markets opening to competition in Victoria:

THRESHOLD	DATE OF ELIGIBILITY	PERCENT OF MARKET	CUSTOMER TYPE
GREATER THAN 5MW..................	Dec 1994	22%	Large heavy industrial
GREATER THAN 1MW..................	July 1995	7%	Large commercial industrial
GREATER THAN 750MWh...............	July 1996	12%	Medium commercial/light industrial
GREATER THAN 160MWh...............	July 1998	8%	Small commercial
All remaining customers...........	January 2001	51%	Residential

NEW ZEALAND

Through a series of transactions in 1998, we gained control of Power New Zealand through the purchase of an additional 48% interest for $245 million, increasing our ownership to 78.6%. Concurrent with this acquisition, we sold our 39.6% interest in New Zealand's WEL Energy Group, which we acquired throughout 1995, 1996, and 1997, and bought out our 21% minority partner in our New Zealand subsidiary, UtiliCorp N.Z, Inc.

New Zealand's Electricity Industry Reform Act of 1998 requires all the country's utilities to separate ownership of their lines (network) and supply (generation and retail) businesses. Power New Zealand, with approximately 90% of its assets and earnings in the lines area, in November 1998 announced its intention to remain in the network business and to exit the supply business. It also agreed to purchase the Wellington-based lines assets of TransAlta New Zealand Ltd. and to sell to TransAlta its retail electricity business serving the Auckland area for a net expenditure by Power New Zealand of $238 million. Because Power New Zealand's name transferred to TransAlta as part of the retail business TransAlta acquired, the network business became UnitedNetworks Limited on January 1, 1999. Also in 1998, Power New Zealand agreed to purchase the electric line assets of neighboring power company TrustPower Limited for approximately $261 million. The assets became part of a greater network which includes parts of metropolitan Auckland and other areas in the central and southern regions of New Zealand's North Island. The TrustPower transaction closed January 1999. Completion of the TransAlta and TrustPower transactions created the country's largest electricity distribution network, serving about 468,000 customers.

UNITED KINGDOM

We market transportation/shipping and balancing services to gas suppliers. The fees we collect are priced as a unit per volume consumed. The gas markets in the United Kingdom are fully competitive with end user customers being able to choose their gas supplier. The deregulation of the gas markets resulted in many new retail gas suppliers competing for the approximately 19 million gas customers in the United Kingdom. As of December 31, 1998, we had approximately 1 million indirect customers, an increase of 900,000 customers since December 31, 1997.

In early 1999 we applied for our electricity supply license. Also this year, we will begin trading electricity and offering a bundled electricity supply service to our customers.

We have developed a European expansion plan and anticipate leveraging our UK operations to begin marketing energy, as deregulation allows, on the European Continent in 1999.

In June 1998, we paid $25.6 million to a third party to cancel two take-or-pay contracts and related guarantees effective April 1, 1998, that required us to take gas at significantly above-market prices until 2005. Between 1995 and 1997, we reserved $19.0 million against the estimated future losses on these contracts, resulting in a "One Time" net settlement loss of $6.6 million.

In July 1998, we lost a long-standing dispute with one of our previous suppliers related to a take-or-pay gas supply contract. We were arguing that the supplier did not make proper deliveries pursuant to the supply contract and further materially breached the contract. Accordingly we began paying the supplier the prevailing market prices which were lower than the contract price. The difference between the two prices accumulated to approximately $38.0 million, an amount we had previously recorded as a liability.

A court ruling required us to pay this $38.0 million price difference along with interest of $6.8 million that accumulated from the date the contract invoices were due. This interest payment was recorded as a one-time loss. We are appealing the court's decision and are seeking recovery of the $44.8 million.

CANADA

We own West Kootenay Power Ltd. (WKP), a hydro-electric utility in British Columbia, Canada. WKP has four hydro-electric generation facilities with a capacity of 205 megawatts and 962 miles of transmission lines that serve approximately 86,000 customers in south central British Columbia. WKP generates about half of its power requirements and purchases the remaining requirements through power contracts.

The following table summarizes the sales, volumes and customers of WKP.

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>	1995 <C>	1994 <C>	1998-1994 CAGR* <C>
Sales (in millions)						
Residential	$ 34.3	$ 36.2	$ 37.0	$ 32.9	$ 34.4	(.1)%
Commercial	18.1	18.8	19.7	19.1	16.6	2.2%
Industrial	8.2	8.5	9.4	9.4	8.7	(1.5)%
Other	26.4	26.3	26.8	26.2	21.2	5.6%
Total	$ 87.0	$ 89.8	$ 92.9	$ 87.6	$ 80.9	1.8%
Volumes (MWH 000s)						
Residential	935	943	990	920	873	1.7%
Commercial	484	474	467	440	421	3.5%
Industrial	263	266	313	319	362	(7.7)%
Other	899	874	909	892	869	.9%
Total	2,581	2,557	2,679	2,571	2,525	.6%
Customers						
Residential	76,172	74,934	73,413	71,844	70,142	2.1%
Commercial	8,378	8,195	8,041	7,888	7,974	1.2%
Industrial	34	36	37	36	36	(1.4)%
Other	1,054	1,060	1,045	1,019	927	3.3%
Total	85,638	84,225	82,536	80,787	78,313	2.3%

</TABLE>

* COMPOUND ANNUAL GROWTH RATE

WKP is regulated by the British Columbia Utilities Commission. The Commission approved renewal of the incentive based rate setting mechanism for 1999. This mechanism was the first of its kind for electric utilities in Canada and was the result of a negotiated settlement with customers and regulators. The mechanism calls for equal sharing of savings between the customer and WKP if WKP performs over and above negotiated performance expectations.

COMPETITION

DOMESTIC UTILITY OPERATIONS

Our domestic utility businesses operate in a regulated environment despite various legislative deregulation efforts at the federal level. Industrial and large commercial customers largely have access to energy sources so some of the competitive pricing benefits have been transferred to these customers through open access tariffs relating to transmission lines and pipelines. Without federal legislation, competition at the retail level cannot form since the rules will be different in each state. Based on our assessment of retail competition possibilities, we reduced most retail activities, preferring to wait until the market develops more fully.

ACCOUNTING IMPLICATIONS

We currently record the economic effects of regulation in accordance with the provisions of Statement of Financial Accounting Standards No. 71 (SFAS 71), "Accounting for the Effects of Certain Types of Regulation." Accordingly, our balance sheet reflects certain costs as regulatory assets. We expect that our rates will continue to be based on historical costs for the foreseeable future. If we discontinued applying SFAS No. 71, we would make adjustments to the carrying value of our regulatory assets. Total net regulatory assets at December 31, 1998 were $96.5 million.

ENERGY MARKETING

Our energy marketing businesses operate in a fully competitive environment that rewards participants on price, service and execution. Our energy marketing businesses compete for customers with some of the largest utility and energy companies in North America. The industry is premised on large volume sales with relatively low margins. Companies that operate in this industry must fully understand the price sensitivity and volatility of commodities. The public became more aware of some of the risks associated with this industry when a number of companies announced sudden losses resulting from the June price spike in electricity. We expect price volatility and we expect events like the June price spike to recur.

OUR EXECUTIVE TEAM

NAME	AGE	POSITION
Richard C. Green, Jr. (Rick)	44	Chairman of the Board and Chief Executive Officer
Robert K. Green (Bob)	37	President and Chief Operating Officer
James G. Miller (Jim)	50	Senior Vice President, Energy Delivery
Charles K. Dempster (Chuck)	56	Senior Vice President; Chairman and Chief Executive Officer, Aquila Energy Corporation
Edward A. Mills (Ed)	39	President and Chief Operating Officer, Aquila Energy Corporation
Jon R. Empson	53	Senior Vice President, Regulatory, Legislative, and Environmental Services
Robert L. Howell	58	Senior Vice President, Corporate Development (will retire April 1, 1999)
Sally C. McElwreath	58	Senior Vice President, Corporate Communications
Leo E. Morton	53	Senior Vice President, Human Resources and Operations Support
Dale J. Wolf	59	Vice President, Finance, Treasurer and Corporate Secretary
James S. Brook (Jim)	49	Vice President, Controller and Chief Accounting Officer
INTERNATIONAL		
Donald G. Bacon (Don)	61	President, West Kootenay Power; Chief Executive Officer, UnitedNetworks Limited
Charles K. Dempster (Chuck)	56	Interim Chairman and President, UtiliCorp U.K., Inc.
Robert K. Green (Bob)	37	Chairman, United Energy Limited; Chairman, UnitedNetworks Limited
R. Paul Perkins	56	Senior Vice President, Australasia
Keith Stamm	38	Chief Executive Officer, United Energy Limited

RICHARD C. GREEN, JR. (B.S. Business--Southern Methodist University)

Rick joined us in 1976 and held various financial and operating positions between 1976 and 1982. In 1982, Rick was appointed Executive Vice President at Missouri Public Service, the predecessor to UtiliCorp. In 1985, Rick became the Chairman, President, and Chief Executive Officer and held those positions until 1996. Rick has been Chairman and Chief Executive Officer since 1996.

ROBERT K. GREEN (B.S. Engineering, Princeton University; J.D. Law, Vanderbilt University)

Bob joined UtiliCorp in 1988 as Assistant Division Counsel and in 1989 was appointed to Division Counsel. Between 1989 and 1992, Bob held executive level positions at Missouri Public Service. In 1993, Bob was appointed Executive Vice President and in 1996 assumed additional duties as President. Bob also is the Chairman of United Energy

Limited, Ltd., a 34% owned foreign traded Australian company and UnitedNetworks Limited, a 79% owned foreign traded New Zealand company.

JAMES G. MILLER (B.S. Electrical Engineering, M.B.A Management, University of Wisconsin)

Jim joined the company in 1983 as President, Michigan Gas Utilities, a company acquired by us in 198X. In 1991, Jim was appointed President, WestPlains Energy and in 1995 was appointed Senior Vice President, Energy Delivery. Prior to Jim's employment at UtiliCorp, Jim worked for Wisconsin Power and Light Company in various financial and operating capacities.

CHARLES K. DEMPSTER (B.S. Civil Engineering, University of Houston)

Chuck joined us in 1993 as President of Aquila Energy Corporation. In 1994, he was appointed Senior Vice President, Energy Resources. In 1995, Chuck became Chairman and CEO of UtiliCorp U.K., Inc and in 1998, Chuck became Senior Vice President, UtiliCorp; Chairman and Chief Executive Officer, Aquila Energy Corporation. Prior to joining us, Chuck was President, Reliance Pipeline Corporation between 1993 and 1987. Prior to 1987, Chuck held executive positions at NICOR and Enron.

EDWARD A. MILLS (University of Texas, M.B.A., Finance, Rice University)

Ed joined our company in 1993 as Director of Risk Management and Trading, Aquila. In 1998, Ed was appointed President and Chief Operating Officer, Aquila Energy. Prior to joining our company, Ed held executive and management positions at Fina Oil and Chemical Company, Texas Commerce Bank, and Springer Holding Company.

JON R. EMPSON (B.A. Economics, Carleton College, M.B.A, Economics, University of Nebraska at Omaha)

Jon joined our company in 1986 as Vice President, Regulation, Finance and Administration. In 1993, Jon was appointed Senior Vice President, Gas Supply and Regulatory Services and in 1996 he was appointed Senior Vice President, Regulatory, Legislative and Environmental Services. Prior to joining UtiliCorp, Jon worked for a predecessor company in various executive and management positions for 7 years, held executive management positions of the Omaha Chamber of Commerce and Omaha Economic Development Council and worked as an economist with the Department of Housing and Urban Development.

SALLY C. MCELWREATH (B.A. Social Sciences, M.B.A. Public Relations, Pace University)

Sally joined us in 1994 as Senior Vice President, Corporate Communications. Prior to joining our company, Sally was Vice President, Corporate Communications for MacMillan Inc. and for The Travel Channel; Director of Marketing Communications for Trans World Airways and Manager of Corporate Communications for United Airlines beginning in 1971. Prior to 1971, she held various positions with ARCO and Sinclair Oil Corporation.

LEO E. MORTON (B.S. Mechanical Engineering, Tuskegee University; M.S. Management, Massachusetts Institute of Technology)

Leo joined our company in 1994 as Senior Vice President, Operations Support and was appointed to his current position in 1996. Prior to working for us, Leo held executive and management positions in manufacturing and engineering for AT&T beginning in 1973.

DALE J. WOLF (B.S. Business Administration, Fort Hays State University; M.B.A Finance, University of Missouri)

Dale joined our company in 1962 as a staff accountant at Missouri Public Service. Between 1962 and 1972, Dale held various accounting and finance positions. In 1972, Dale was appointed Assistant Treasurer and in 1976, Treasurer. In 1984, Dale was promoted to Vice President and Treasurer for Missouri Public Service. When UtiliCorp was formed in 1985, Dale became its Vice President, Finance and Treasurer. In 1989, Dale assumed the Corporate Secretary responsibilities.

JAMES S. BROOK (B.S. Commerce, University of Manitoba, Chartered Accountant; M.B.A. University of Kansas)

Jim joined our company in 1976 as a financial assistant at West Kootenay Power. In 1978, Jim was appointed to Manager, Financial Administration and in 1980, Jim was appointed as Chief Financial Officer. In 1990, Jim was appointed to Senior Vice President, Administration at Missouri Public Service and in 1993 was appointed to his current position at Corporate.

DONALD G. BACON (B.S. Civil Engineering, University of Alberta)

Don joined our company in 1993 as President of West Kootenay Power. In 1997, Don became Power New Zealand's Chief Executive Officer in addition to his responsibilities in Canada. Prior to Don's employment with us, he was a Vice President at TransAlta Utilities Corporation between 1988 and 1993 and in various operating positions from 1975 and 1988.

R. PAUL PERKINS (B.A. International Relations, University of North Carolina)

Paul joined us in 1994 as Vice President, Corporate Development. Paul's primary focus in Corporate Development was in international opportunities. In 1997, Paul was appointed Senior Vice President, Australia. Prior to joining UtiliCorp, Paul was a regional manager for WMX Technologies between 1992 and 1994 focusing on Latin America and the Caribbean. Paul worked for Texaco Inc. as a Division Manager, Supply and Trading for Latin America and West Africa between 1990 and 1992. Paul worked for Texaco between 1978 and 1990 in other international capacities.

KEITH G. STAMM (B.S. Mechanical Engineering, University of Missouri at Columbia; M.B.A. Finance, Rockurst College. Licensed professional engineer)

Keith joined our company in 1983 as a staff engineer at our Sibley Power Plant. Between 1985 and 1995, Keith held various operating positions. In 1995, Keith was promoted to Vice President, Energy Trading and in 1996, promoted to Vice President and General Manager, Regulated Power. In 1997, Keith became the Chief Executive Officer of United Energy Limited.

ITEM 2. PROPERTIES.

We own electric production, transmission and distribution systems and gas transmission and distribution systems throughout our service territories. We also own gas gathering, processing and pipeline systems. Substantially all utility plant assets in Michigan are mortgaged pursuant to an Indenture of Mortgage and Deed of Trust dated July 1, 1951, as supplemented. Substantially all of our Canadian utility plant is mortgaged under terms of a separate indenture.

UTILITY FACILITIES

Our electric generation plants, as of December 31, 1998, are as follows:

<TABLE>
<CAPTION>

UNIT	LOCATION	YEAR INSTALLED	UNIT CAPABILITY (KW NET, PER HOUR)	FUEL	NET GENERATION (MW HOURS)
<S>	<C>	<C>	<C>	<C>	<C>
MISSOURI:					
Sibley #1 - #3	Sibley	1960, 1962, 1969	496,000	Coal	3,090,148
Ralph Green #3	Pleasant Hill	1981	74,000	Gas	35,100
Nevada	Nevada	1974	20,000	Oil	1,117
Greenwood #1 - #4	Greenwood	1975 - 1979	247,000	Gas/Oil	200,524
KCI #1 and #2	Kansas City	1970	33,000	Gas	6,876
KANSAS:					
Judson Large #4	Dodge City	1969	143,000	Gas	386,481
Arthur Mullergren #3	Great Bend	1963	90,000	Gas	258,932
Cimarron River #1 -- #2	Liberal	1963, 1967	72,000	Gas	145,822
Clifton #1 -- #2	Clifton	1974	73,000	Gas/Oil	45,563
Jeffrey #1 -- #3	St. Mary's	1978, 1980, 1983	352,000	Coal	2,223,054
COLORADO:					
W.N. Clark #1 -- #2	Canon City	1955, 1959	40,000	Coal	220,789
Pueblo #6	Pueblo	1949	20,000	Gas	6,969
Diesel #'s 1,2,3,4,5	Pueblo	1964	10,000	Oil	837
Diesel #'s 1,2,3,4,5	Rocky Ford	1964	10,000	Oil	596
CANADA:					
No. 1	Lower Bonnington, BC	1925	42,000	Hydro	296,796
No. 2	Upper Bonnington, BC	1907	60,000	Hydro	437,944
No. 3	South Slocan, BC	1928	53,000	Hydro	428,771
No. 4	Corra Linn, BC	1932	50,000	Hydro	349,381
TOTAL			1,885,000		8,135,700

</TABLE>

The following table shows the overall fuel mix and generation capability for the past five years.

<TABLE>
<CAPTION>

SOURCE (MW)	1998	1997	1996	1995	1994

<S>	<C>	<C>	<C>	<C>	<C>
Coal	888	889	885	875	868
Gas and oil	792	790	784	705	705
Hydro	205	205	205	205	205
Total generation capability	1,885	1,884	1,874	1,785	1,778

</TABLE>

At December 31, 1998, we had transmission and distribution lines as follows:

<TABLE>
<CAPTION>

DESCRIPTION	LENGTH (POLE MILES)
<S>	<C>
Transmission lines	5,295
Overhead distribution lines	21,043
Underground distribution lines	6,976
Total	33,314

</TABLE>

At December 31, 1998, our gas utility operations had 2,122 miles of gas gathering and transmission pipelines and 24,056 miles of distribution mains and service lines located throughout its service territories.

GAS PROCESSING AND GATHERING ASSETS

AQP owned and/or operated 11 active natural gas pipeline systems with an aggregate length of approximately 3,403 miles. These pipelines do not form an interconnected system. Set forth below is information with respect to AQP's pipeline systems as of December 31, 1998:

<TABLE>
<CAPTION>

GATHERING SYSTEMS	LOCATION	MILES OF PIPELINE (A)	GAS THROUGHPUT CAPACITY (A)(B) (MMCF/D)	AVG. DAILY GAS THROUGHPUT (A)(B)(C) (MMCF/D)
<S>	<C>	<C>	<C>	<C>
Southeast Texas/Katy	SE Texas	2,338	732	381
Mentone	W. Texas	13	60	--
Gomez	W. Texas	11	40	--
Menard County	C. Texas	120	30	2
Maverick County	W. Texas	121	20	2
Rhoda Walker	W. Texas	21	20	2
Panola County	E. Texas	23	8	1
Elk City	SW Oklahoma	163	100	69
Mooreland	NW Oklahoma	324	40	11
Brooks-Hidalgo--23%(d)	S. Texas	--	--	1
Dorado--40%	S. Texas	58	40	9
Benedum/Wilshire--20%	W. Texas	211	130	14
		3,403	1,220	492
Fuel and Shrinkage		--	--	(17)
Total		3,403	1,220	475

</TABLE>

(a) All mileage, capacity and volume information is approximate. Capacity figures are management's estimates based on existing facilities without regard to the present availability of natural gas.

(b) Gross gas throughput capacity is included at 100% while average gas throughput is presented at the our present joint venture ownership interest.

(c) Excludes off-system marketing sales with average daily volumes of 795 MMcf/d sold from other companies' facilities

(d) In March 1998, Brooks-Hidalgo Joint Venture's ownership interests in its assets were sold.

At December 31, 1998, we owned 35% of the capital stock of Oasis and the right to transport 280 MMcf/d of natural gas on Oasis' pipeline, plus the opportunity to utilize excess capacity on an interruptible basis. The Oasis pipeline is a 600-mile, 36-inch diameter natural gas pipeline which connects

the Waha, Texas hub to the Katy, Texas hub. The Oasis pipeline has a 1 Bcf/d of throughput capacity. We use the equity method of accounting for this investment.

At December 31, 1997, AQP owned and/or operated an interest in four natural gas processing plants. Set forth below is information with respect to AQP's processing plants as of December 31, 1998:

PROCESSING PLANTS	GAS THROUGHPUT CAPACITY(A) (MMCF/D)	GAS THROUGHPUT (A),(B) (MMCF/D)	NGLS PRODUCTION (A),(B) (MBBLS/D)(D)
La Grange, Texas	230	165	20.2
Somerville, Texas	28	19	.5
Benedum, Texas 20%	125	14	.9
Elk City, Oklahoma	115	69	3.5
Total owned plants	498	267	25.1
Katy, Texas(d)	--	173	--
Total	498	440	25.1

(a) All capacity and volume information is approximate. Capacity figures are management's estimates based on existing facilities without regard to the present availability of natural gas.

(b) Volumes from joint ventures have been included at the present AQP ownership interest.

(c) Thousands of barrels per day (MBbls/d).

(d) This plant is owned and operated by a third party from which AQP receives a portion of the NGLs produced from gas AQP delivers to the plant. The plant is included in this section for informational purposes to show the gas throughput and NGLs production that AQP received utilizing the access to this plant.

The availability of natural gas reserves to AQP depends on their development in the area served by its pipelines and on AQP's ability to purchase gas currently sold to or transported through other pipelines. The development of additional gas reserves will be affected by many factors including the prices of natural gas and crude oil, exploration and development costs and the presence of natural gas reserves in the areas served by AQP's systems.

INDEPENDENT POWER PROJECTS

Information regarding the company's generating projects is set forth below.

PROJECT & LOCATION	TYPE OF INVESTMENT	PERCENT OWNED	CAPACITY (MW)(A)	FUEL	DATE IN SERVICE
Mega Renewables G.P., 4 projects in California	General partnership	49.75%	12.2	Hydro	Spring 1987(b)
Topsham Hydro Partners, Maine	Leveraged lease	50	13.9	Hydro	October 1987
Stockton CoGen Company, California	General partnership	50	60.0	Coal	March 1988(c)
Westwood Energy Properties, Pennsylvania	Limited partnership	38	29.25	Waste coal	July 1988
BAF Energy L.P., California	Limited partnership	23.1	120.0	Natural Gas	May 1989
Rumford Cogeneration Company L.P., Maine	Limited partnership	24.3	85.0	Coal and waste wood	May 1990
Koma Kulshan Associates, Washington	Limited partnership	49.75	13.7	Hydro	October 1990
Badger Creek Limited, California	Limited partnership	49.75	50.0	Natural gas	April 1991

McKittrick Limited, California	Limited partnership	49.75	50.0	Natural gas	October 1991
Live Oak Limited, California	Limited partnership	50	50.0	Natural gas	April 1992
Lockport Energy Associates, L.P., New York	Limited partnership	16.58	180.0	Natural gas	December 1992
Orlando Cogen Limited, L.P., Florida	Limited partnership	50	125.7	Natural gas	September 1993
Naheola Cogeneration LP, Alabama	Limited partnership	50	81.2	Black liquor solids, coal, gas, wood	March 1993(d)
Jamaica Private Power Company, Jamaica	Limited liability Company	24.09	60.0	Diesel	January 1997

</TABLE>

(a) Nominal gross capacity.

(b) Interest acquired by the company in June 1989.

(c) Interest acquired by the company in December 1988.

(d) Interest acquired by the company in May 1995.

ITEM 3. LEGAL PROCEEDINGS.

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

There were no matters submitted to a vote of security holders in the fourth quarter of 1998.

PART 2

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS.

The company's common stock (par $1) is listed on the New York, Pacific and Toronto stock exchanges under the symbol UCU. At December 31, 1998, the company had 41,027 common shareholders of record. Information relating to market prices of common stock and cash dividends on common stock is set forth in the table below.

MARKET PRICE

<TABLE>
<CAPTION>

<S>	HIGH(A) <C>	LOW(A) <C>	CASH DIVIDENDS(A) <C>
1998 QUARTERS			
First	$ 26.29	$ 23.33	$ .30
Second	26.33	23.21	.30
Third	26.25	22.63	.30
Fourth	24.46	22.87	.30
1997 QUARTERS			
First	$ 18.83	$ 17.00	$ .2933
Second	19.59	17.17	.2933
Third	20.59	19.33	.2933
Fourth	26.04	20.09	.2933

</TABLE>

(a) All per share amounts have been restated for the 3-for-2 stock split.

ITEM 6. SELECTED FINANCIAL DATA.

<TABLE>
<CAPTION>

<S>	1998 <C>	1997 <C>	1996 <C>	1995 <C>	1994 <C>
		IN MILLIONS (EXCEPT PER SHARE)			
Sales	$ 12,563.4	$ 8,926.3	$ 4,332.3	$ 2,792.6	$ 2,398.1
Income from operations	240.8	243.3	225.8	227.1	228.0
Net income	132.2	122.1	105.8	79.8	94.4
Earnings available for common shares	132.2	121.8	103.7	77.7	91.4
Basic earnings per common share (a)	1.65	1.51	1.46	1.15	1.39
Cash dividends per common share (a)	1.20	1.17	1.17	1.15	1.13
Total assets	5,991.5	5,113.5	4,739.8	3,885.9	3,111.1
Short-term debt (including current maturities)	484.4	263.4	277.7	303.7	321.2

Long-term debt	1,375.8	1,358.6	1,470.7	1,355.4	976.9
Company-obligated mandatorily redeemable preferred securities of a partnership	100.0	100.0	100.0	100.0	--
Preference and preferred stock	--	--	25.0	25.4	25.4
Common shareholders' equity	1,446.3	1,163.6	1,158.0	946.3	906.8

</TABLE>

(a) All per share amounts have been restated for the 3-for-2 stock split.

Items between years that impact comparability are described and are incorporated by reference on page 27 in the company's 1998 Annual Report to Shareholders.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION.

The information required by this item is incorporated by reference to pages 27 through 39 in the company's 1998 Annual Report to Shareholders.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The information required by this item is incorporated by reference to pages 36 and 37 in the company's Annual Report to Shareholders.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item is incorporated by reference to pages 40 through 60 of the company's 1998 Annual Report to Shareholders.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

PART 3

ITEMS 10, 11, 12 AND 13. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY, EXECUTIVE COMPENSATION, SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT, AND CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Information regarding these items appear in our proxy statement and is hereby incorporated by reference in this Annual Report on Form 10-K. For information with respect to the executive officers of the company, see "Executive Officers of the Registrant" following Item 1 in Part 1 of this Form 10-K.

PART 4

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K.

(A) THE FOLLOWING DOCUMENTS ARE FILED AS PART OF THIS REPORT:

(1) FINANCIAL STATEMENTS:

<TABLE>
<CAPTION>

<S>	PAGE NO. <C>
Consolidated Statements of Income for the three years ended December 31, 1998	*
Consolidated Balance Sheets at December 31, 1998 and 1997	*
Consolidated Statements of Common Shareowners' Equity for the three years ended December 31, 1998	*
Consolidated Statements of Comprehensive Income for the three years ended December 31, 1998	*
Consolidated Statements of Cash Flows for the three years ended December 31, 1998	*
Notes to Consolidated Financial Statements	*
Report of Independent Public Accountants	*

</TABLE>

----

* Incorporated by reference to pages 40 through 60 of the company's 1998 Annual Report to Shareholders.

(2) FINANCIAL STATEMENT SCHEDULE

<TABLE>
<S> <C>
Report of Independent Accountants on Financial Statement Schedule

</TABLE>

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(3) LIST OF EXHIBITS *

The following exhibits relate to a management contract or compensatory plan or arrangement:

<TABLE>

<S>	<C>
10(a)(2)	UtiliCorp United Inc. Deferred Income Plan.
10(a)(3)	UtiliCorp United Inc. Amended and Restated 1986 Stock Incentive Plan.
10(a)(4)	UtiliCorp United Inc. Annual and Long-Term Incentive Plan.
10(a)(5)	UtiliCorp United Inc. 1990 Non-Employee Director Stock Plan.
10(a)(6)	Severance Compensation Agreement.
10(a)(7)	Executive Severance Payment Agreement.
10(a)(8)	Split Dollar Agreement.
10(a)(9)	Supplemental Retirement Agreement.
10(a)(11)	UtiliCorp United Inc. Life Insurance Program for Officers.
10(a)(12)	Summary of Terms and Conditions of Employment of Charles K. Dempster.
10(a)(13)	Supplemental Executive Retirement Plan, Amended and Restated.
10(a)(14)	Employment Agreement for Richard C. Green, Jr.
10(a)(15)	Employment Agreement for Robert K. Green.
10(a)(16)	Capital Accumulation Plan.
10(a)(17)	Supplemental Contributory Retirement Plan.

</TABLE>

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* Incorporated by reference to the Index to Exhibits.

(b) Reports on Form 8-K

A current report on Form 8-K dated November 13, 1998, filed on November 16, 1998, with respect to Item 5 and Item 7 was filed with the Securities and Exchange Commission by the Registrant.

A current report on Form 8-K dated December 10, 1998, filed on December 14, 1998, with respect to Item 7 was filed with the Securities and Exchange Commission by the Registrant.

REPORT OF INDEPENDENT ACCOUNTANTS ON FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Shareholders of UtiliCorp United Inc.:

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements for 1998, 1997 and 1996 described on page 60 of UtiliCorp United Inc.'s Annual Report to shareholders, which is incorporated by reference in this Form 10-K, and have issued our report thereon dated February 1, 1999. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The Financial Statement Schedule listed in Item 14(a)2 is the responsibility of the company's management and is presented for the purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audit of the basic consolidated financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

/s/ ARTHUR ANDERSEN LLP

Kansas City, Missouri
February 1, 1999

UTILICORP UNITED INC.
SCHEDULE II--VALUATION AND QUALIFYING ACCOUNTS

FOR THE THREE YEARS ENDED DECEMBER 31, 1998
(IN MILLIONS)

<TABLE>
<CAPTION>

COLUMN A DESCRIPTION	COLUMN B BEGINNING BALANCE AT DECEMBER 31	COLUMN C PURCHASE OF A BUSINESS	COLUMN D ADDITIONS CHARGED TO EXPENSE	COLUMN E DEDUCTIONS FROM RESERVES FOR PURPOSES FOR WHICH CREATED	COLUMN F ENDING BALANCE AT DECEMBER 31
<S>	<C>	<C>	<C>	<C>	<C>
Price Risk Management credit and service reserves:					
1998.........................	$ 60.4	--	--	7.9	$ 52.5
1997.........................	$ 57.2	--	3.2	--	$ 60.4
1996.........................	$ 70.6	--	--	13.4	$ 57.2
Reserve for United Kingdom gas contracts					
1998.........................	$ 19.0	--	6.6	25.6	$ --
1997.........................	$ 14.0	--	5.0	--	$ 19.0
1996.........................	$ 11.0	--	3.0	--	$ 14.0

</TABLE>

UTILICORP UNITED INC.
INDEX TO EXHIBITS

<TABLE>
<CAPTION>

EXHIBIT NUMBER	DESCRIPTION
<S>	<C>
*3(a)(1)	Certificate of Incorporation of the Company. (Exhibit 3(a)(1) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*3(a)(2)	Certificate of Amendment to Certificate of Incorporation of the Company. (Exhibit 4(a)(1) to Registration Statement No. 33-16990 filed September 3, 1987.)
*3(a)(3)	By-laws of the Company as amended. (Exhibit 3.1 on Form 10-Q for the quarter ended June 30, 1998.)
*4(a)(1)	Certificate of Incorporation of the Company. (Exhibit 4(a)(1) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*4(a)(2)	Certificate of Amendment to Certificate of Incorporation of the Company. (Exhibit 3.2 on Form 10-Q for the quarter ended June 30, 1998.)
*4(b)(1)	Indenture, dated as of November 1, 1990, between the Company and The First National Bank of Chicago, Trustee. (Exhibit 4(a) to the Company's Current Report on Form 8-K, dated November 30, 1990.)
*4(b)(2)	First Supplemental Indenture, dated as of November 27, 1990. (Exhibit 4(b) to the Company's Current Report on Form 8-K, dated November 30, 1990.)
*4(b)(3)	Second Supplemental Indenture, dated as of November 15, 1991. (Exhibit 4(a) to UtiliCorp United Inc.'s Current Report on Form 8-K dated December 19, 1991.)
*4(b)(4)	Third Supplemental Indenture, dated as of January 15, 1992. (Exhibit 4(c)(4) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*4(b)(5)	Fourth Supplemental Indenture, dated as of February 24, 1993. (Exhibit 4(c)(5) to the Company's Annual Report on Form 10-K for the year ended December 31, 1992.)
*4(b)(6)	Fifth Supplemental Indenture, dated as of April 1, 1993. (Exhibit 4(c)(6) to the Company's Annual Report on Form 10-K for the year ended December 31, 1993.)
*4(b)(7)	Sixth Supplemental Indenture, dated as of November 1, 1994. (Exhibit 4(d)(7) to the Company's Registration Statement on Form S-3 No. 33-57167, filed January 4, 1995.
*4(b)(8)	Seventh Supplemental Indenture, dated as of June 1, 1995. (Exhibit 4 to the Company's Form 10-Q for the period ended June 30, 1995.)
*4(b)(9)	Eighth Supplemental Indenture, dated as of October 1, 1996 (Exhibit 4(b)(9) to the company's Annual Report on Form 10-K for the year ended December 31, 1996).
*4(b)(10)	Ninth Supplemental Indenture, dated as of September 1, 1997 (Exhibit 4 to the company's quarterly report on Form 10-Q for the period ended September 30, 1997).
*4(c)	Twentieth Supplemental Indenture, dated as of May 26, 1989, Supplement to Indenture of Mortgage and Deed of Trust, dated July 1, 1951. (Exhibit 4(d) to Registration Statement No. 33-45382, filed January 30, 1992.)
	Long-Term debt instruments of the Company in amounts not exceeding 10 percent of the total assets of the Company and its subsidiaries on a consolidated basis will be furnished to the Commission upon request.

</TABLE>

26

<TABLE>
<CAPTION>

EXHIBIT NUMBER	DESCRIPTION
<S>	<C>
*4(d)(1)	Indenture, dated as of June 1, 1995, Junior Subordinated Debentures. (Exhibit 4(d)(1) to the company's Annual Report on Form 10-K for the year ended December 31, 1995.)
*4(d)(2)	First Supplemental Indenture, dated as of June 1, 1995, Supplement to Indenture dated June 1, 1995. (Exhibit 4(d)(2) to the company's Annual Report on Form 10-K for the year ended December 31, 1995.)
*4(e)]	Form of Rights Agreement between UtiliCorp United Inc. and First Chicago Trust Company of New York, as Rights Agent. (Exhibit 4 to the company's Form 10-Q for the period ended September 30, 1996.)
*10(a)(1)	Agreement for the Construction and Ownership of Jeffrey Energy Center, dated as of January 13, 1975, among Missouri Public Service Company, The Kansas Power & Light Company, Kansas Gas and Electric Company and Central Telephone & Utilities Corporation. (Exhibit 5(e)(1) to Registration Statement No. 2-54964, filed November 7, 1975.)
*10(a)(2)	UtiliCorp United Inc. Deferred Income Plan. (Exhibit 10(a)(2) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*10(a)(3)	UtiliCorp United Inc. Amended and Restated 1986 Stock Incentive Plan. (Exhibit 10.3 to the company's Form 10-Q for the quarter ended June 30, 1998.)
*10(a)(4)	UtiliCorp United Inc. Annual and Long-Term Incentive Plan. (Exhibit 10.4 to the Company's Form 10-Q for the quarter ended June 30, 1998).
*10(a)(5)	UtiliCorp United Inc. 1990 Non-Employee Director Stock Plan. (Exhibit 10(a)(5) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*10(a)(6)	Form of Severance Compensation Agreement between UtiliCorp United Inc., and certain Executives of the Company. (Exhibit 10 (a)(7) to the company's Annual Report on Form 10-K for the year ended December 31, 1995.)
*10(a)(7)	Executive Severance Payment Agreement (Exhibit 10 to the Company's Quarterly Report on Form 10-Q filed for the quarter ended September 30, 1993.)
*10(a)(8)	Split Dollar Agreement dated as of June 12, 1985, between the Company and James G. Miller. (Exhibit 10(a)(10) to the Company's Annual Report on Form 10-K for the year ended December 31, 1994.)
*10(a)(9)	Supplemental Retirement Agreement dated as of January 27, 1983, between the Company and James G. Miller. (Exhibit 10(a)(11) to the Company's Annual Report on Form 10-K for the year ended December 31, 1994.)
*10(a)(10)	Lease Agreement dated as of August 15, 1991, between Wilmington Trust Company, as Lessor, and the Company, as Lessee. (Exhibit 10(a)(13) to the Company's Annual Report on Form 10-K for the year ended December 31, 1991.)
*10(a)(11)	UtiliCorp United Inc. Life Insurance Program for Officers. (Exhibit 10 (a)(13) to the company's Annual Report on Form 10-K for the year ended December 31, 1995.)
*10(a)(12)	Summary of Terms and Conditions of Employment of Charles K. Dempster. (Exhibit 10 to the company's quarterly report on Form 10-Q for the period ended March 31, 1996.)
*10(a)(13)	Supplemental Executive Retirement Plan, Amended and Restated, effective as of January 1, 1998. (Exhibit 10.1 on Form 10-Q for the quarter ended June 30, 1998.)

</TABLE>

27

<TABLE>
<CAPTION>

EXHIBIT NUMBER	DESCRIPTION
<S>	<C>
*10(a)(14)	Employment Agreement for Richard C. Green, Jr. (Exhibit 10.4 on Form 10-Q for the quarter ended June 30, 1998.)
*10(a)(15)	Employment Agreement for Robert K. Green (Exhibit 10.5 on Form 10-Q for the quarter ended June 30, 1998.)
*10(a)(16)	Capital Accumulation Plan, effective as of January 1, 1998. (Exhibit 10(a)(1) to the company's Form 10-Q for the quarter ended March 31, 1998.)
*10(a)(17)	Supplemental Contributory Retirement Plan, effective as of January 1, 1998. (Exhibit 10(a)(2) to the company's Form 10-Q for the quarter ended March 31, 1998.)

13	Annual Report to Shareholders for the year ended December 31, 1998
21	Subsidiaries of the Company.
23	Consent of Arthur Andersen LLP.
27	Financial Data Schedule.

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* Exhibits marked with an asterisk are incorporated by reference as indicated pursuant to Rule 12(b)-23.

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, there unto duly authorized.

UTILICORP UNITED INC.

By:	/s/ RICHARD C. GREEN, JR. ---------------------------- Richard C. Green, Jr.	Chairman of the Board of Directors, Chief Executive Officer (Principal Executive Officer)
Date: March 25, 1999		

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 dates indicated.

By:	/s/ RICHARD C. GREEN, JR. ---------------------------- Richard C. Green, Jr.	Chairman of the Board of Directors, Chief Executive Officer (Principal Executive Officer)
Date: March 25, 1999		
By:	/s/ ROBERT K. GREEN ---------------------------- Robert K. Green	President, Chief Operating Officer and Director
Date: March 25, 1999		
By:	/s/ JAMES S. BROOK ---------------------------- James S. Brook	Vice President, Controller and Chief Accounting Officer
Date: March 25, 1999		
By:	/s/ JOHN R. BAKER ---------------------------- John R. Baker	Director
Date: March 25, 1999		
By:	/s/ AVIS G. TUCKER ---------------------------- Avis G. Tucker	Director
Date: March 25, 1999		

<TABLE>
<S>   <C>   <C>

By:	/s/ ROBERT F. JACKSON ---------------------------- Robert F. Jackson	Director
Date: March 25, 1999		
By:	/s/ L. PATTON KLINE ---------------------------- L. Patton Kline	Director
Date: March 25, 1999		
By:	/s/ HERMAN CAIN ---------------------------- Herman Cain	Director
Date: March 25, 1999		
By:	/s/ IRVINE O. HOCKADAY, JR. ---------------------------- Irvine O. Hockaday, Jr.	Director
Date: March 25, 1999		
By:	/s/ DR. STANLEY O. IKENBERRY ---------------------------- Dr. Stanley O. Ikenberry	Director
Date: March 25, 1999		

</TABLE>

Exhibit 13

FIRST MOVER

FINANCIAL REVIEW

Consolidated Operations

This review of 1998 performance is organized by business segments, reflecting the way we manage our businesses. Each business unit leader is responsible for operating results expressed as earnings before interest and taxes (EBIT). Therefore each segment discussion focuses on the factors affecting EBIT.

We make all decisions on finance, dividends and taxes at the corporate level. We discuss those topics separately on a consolidated basis. Our main financial performance objectives are: -

<TABLE>
<CAPTION>

<S>	Objective <C>	1998 Result <C>
Earnings per share growth	8%	8.0%
Total 3-year return to shareholders	Exceed peer group average*	45.1%
Dividend growth	2%	2.3%

</TABLE>

* We compare our total return to that of 12 top-tier competitors that are similar in terms of customers, employees and markets. In 1998 the peer group had an average 3-year return of 40.9%.

A summary of our normalized EBIT by business segment is shown below.

<TABLE>
<CAPTION>

Dollars in millions <S>	1998 <C>	<C>	1997 <C>	1996 <C>	Long-Term Future Growth Rate* <C>
Regulated Businesses	$210.2	60.5%	$197.5	$206.3	2%
Aquila Energy:					
Aquila Gas Pipeline	18.6	5.4	51.8	51.4	3%
Aquila Marketing	20.5	5.9	18.4	(4.2)	20%+
Independent power projects	32.2	9.2	27.7	22.1	4%
Total Aquila Energy	71.3	20.5	97.9	69.3	20%
International:					
Australia	22.3	6.5	27.0	38.3	
Canada	22.0	6.3	26.2	27.7	
New Zealand	21.4	6.2	9.9	11.6	
United Kingdom	6.2	1.8	(5.6)	2.1	
Total International	71.9	20.8	57.5	79.7	6%-20%
Corporate and other	(6.2)	(1.8)	(13.8)	(39.0)	
Total Normalized EBIT	$347.2	100.0%	$339.1	$316.3	6.5%
Normalized Earnings Per Share--Diluted	$1.62		$1.50	$1.39	8%

</TABLE>

* Management estimate.

<TABLE>

Earnings Per Share Growth

<S>	<C>	<C>	<C>
98		+8%...........	1.62
97		+8%...........	1.50
96...			1.39
0	.50	1.00	1.50

DILUTED AND NORMALIZED--DOLLARS

</TABLE>

Our goal is to grow earnings per share by 8% per year, which is significantly faster than the industry average. We set this goal in mid-1997 and have achieved it two years in a row.

<TABLE>
<CAPTION>

CAPITAL EMPLOYED

<S>	<C>
98	3,406.5
97	2,885.6
96	3,031.4

0 1,000 2,000 3,000

DOLLARS IN MILLIONS

</TABLE>

Capital employed represents the dollars invested in the business. Our capital employed increased more than $500 million in 1998 due to recent investments in New Zealand and additional working capital.

THE MAIN FACTORS SHAPING 1998 RESULTS

Comparison to 1997 Normalized Diluted Earnings Per Share

<TABLE>
<CAPTION>

NEGATIVE FACTORS:		POSITIVE FACTORS:	
Missouri rate case (a)	$(.12)	International growth (d)	$.17
Depressed natural gas liquids prices and production (b)	(.23)	Regulated Businesses (e)	.35
Mild weather (c)	(.12)	Aquila term business (f)	.05
		Corporate and other	.02
TOTAL NEGATIVE FACTORS	$(.47)	TOTAL POSITIVE FACTORS	$.59
NET CHANGE FROM 1997			$.12

</TABLE>

(a) In April 1998, we were ordered by the Missouri Public Service Commission to reduce rates by $22.7 million annually, or $16.3 million prorated in 1998.

(b) Natural gas liquids prices and production declined 26% and 32%, respectively.

(c) Winter temperatures as measured by heating degree-days were off 15%, partially offset by warmer summer temperatures.

(d) Our International growth came from New Zealand and the United Kingdom.

(e) Off-system volume growth, customer additions and the weather recovery plan were all contributors.

(f) Aquila's term business came on strong, signing over 700 transactions in 1998.

NON-RECURRING ITEMS

Our normalized earnings before interest and taxes (EBIT) for the three years ended December 31, 1998 were affected by several items that we expect will not have a continuing impact on UtiliCorp's financial position or results from operations. The table below summarizes the effect of non-recurring items on EBIT.

<TABLE>
<CAPTION>

	Year Ended December 31,		
In millions	1998	1997	1996
EBIT, as reported	$351.4	$359.1	$326.2
Non-recurring items:			
Merger termination fee (a)	--	(53.0)	--
Write-off of deferred merger costs, net (a)	--	--	11.0
Gain on sales lease of a power project (b)	--	--	(20.9)
Provision for asset impairments (c)	27.7	26.5	--
United Kingdom gas contract settlements and other reserves (d)	13.4	6.5	--
Australia initial public offering (e)	(45.3)	--	--
Normalized EBIT	$347.2	$339.1	$316.3

</TABLE>

(a) In 1997, we received $53.0 million from Kansas City Power & Light Company as a merger termination fee. In 1996, we expensed all previously deferred merger costs and recorded an $11.0 million charge against earnings.
(b) In 1996, we recorded a gain from a sales lease on a power project. The gain was partially offset by certain restructuring reserves related to changes in power project agreements. The result of these items increased EBIT $20.9 million.
(c) In 1998, we recorded a $27.7 million provision for impaired assets relating to certain retail gas marketing assets, termination of EnergyOne L.L.C., and the write-off of an independent power project. In 1997, we recorded a provision for impaired assets of $26.5 million related to certain technology and royalty assets.
(d) In 1998, we settled two above-market gas contracts at a net loss of $6.6 million. In addition, a judgement against us on a disputed gas supply contract requires us to record $6.8 million in interest related to the contract. In 1997, we recorded a $6.5 million reserve primarily for unfavorable gas supply contracts in the United Kingdom.
(e) In 1998, United Energy Limited (UEL) sold 42% of its common stock to the public in Australia. UtiliCorp recorded a $45.3 million gain from the sale.

We use the term "normalized EBIT" to describe our recurring earnings before interest and taxes excluding non- recurring items. The term is not meant to replace actual EBIT or other performance measures used under generally accepted accounting principles.

REGULATED BUSINESSES

The following table summarizes the domestic Regulated Businesses for the three years ended December 31, 1998.

THREE-YEAR REVIEW--REGULATED BUSINESSES

<TABLE>
<CAPTION>

	Year Ended December 31,		
Dollars in millions	1998	1997	1996
<S>	<C>	<C>	<C>
Sales:			
Electric	$616.6	$557.4	$519.3
Gas	622.5	767.4	727.9
Other	233.7	258.7	124.8
Total sales	1,472.8	1,583.5	1,372.0
Cost of sales:			
Electric	235.0	199.1	179.1
Gas	365.4	493.2	455.2
Other	199.1	223.0	84.5
Total cost of sales	799.5	915.3	718.8
Gross profit	673.3	668.2	653.2
Operating expenses:			
Other operating	256.6	282.4	275.9
Maintenance	49.0	47.7	40.6
Taxes, other than income taxes	54.0	61.2	57.5
Depreciation and amortization	109.1	85.0	83.2
Provision for asset impairments	2.5	--	--
Total operating expenses	471.2	476.3	457.2
Income from operations	202.1	191.9	196.0
Other income	5.6	5.6	10.3
Earnings before interest and taxes (EBIT)	207.7	197.5	206.3
Non-recurring items:			
Provision for asset impairments	2.5	--	--
Normalized EBIT	$210.2	$197.5	$206.3
Normalized EBIT contribution to UtiliCorp	60.5%	58.2%	65.2%
Identifiable assets	$2,040.9	$2,101.9	$2,061.0
Electric sales and transportation (MWH 000's)	12,443	11,201	9,607
Gas sales and transportation (MCF 000's)	250,010	287,396	301,513

Electric customers	373,000	365,000	359,000
Gas customers	852,000	829,000	813,000
Appliance service customers	171,000	170,000	169,000
Total customers	1,396,000	1,364,000	1,341,000

</TABLE>

<TABLE>
<CAPTION>

ELECTRIC SALES AND TRANSPORTAION

<S>	<C>
98	12,443
97	11,201
96	9,607

0 3,000 6,000 9,000 12,000

MWH 000s

</TABLE>

Electric volumes increased due to additional customers and higher volumes sold outside our network area.

<TABLE>
<CAPTION>

COST OF POWER GENERATED

<S>	<C>
UTILICORP	14.96
COMPETTITORS	17.78

0 0 5 10 15

DOLLARS PER MWH

</TABLE>

Our cost to generate power at our larger baseload plants (coal-fired plants with over 150 MW capacity) is 16% lower than costs at similar plants in the area owned by others.

<TABLE>
<CAPTION>

GAS SALES AND TRANSPORTATION

<S>	<C>
98	250,010
97	287,396
96	301,513

0 100,000 200,000 300,000

MCF 000s

</TABLE>

Gas volumes decreased 17% since 1996 due to warmer weather and lower demand for transportation services.

[PHOTO]
As Senior Vice President, Energy Delivery, Jim Miller oversees UtiliCorp's electric and natural gas utility operations, which serve 1.2 million customers in eight states.

[PHOTO]
Heading up Aquila Energy's new leadership team are Chuck Dempster (left), Chairman and Chief Executive Officer, and Ed Mills, President and Chief Operating Officer.

GROSS PROFIT

Gross profit from Regulated Businesses in 1998 was $5.1 million more than in 1997. This is due to a 2.6% increase in utility customers, higher customer usage and energy sales that together increased gross profit by $29.2 million. Partially offsetting this increase were the impact of mild weather, which reduced gross profit by $16.6 million, and the effects of a rate reduction in Missouri. The rate reduction became effective in April and reduced gross profit by $12.0 million. The Missouri rate order also increased depreciation expense by $4.3 million. Winter weather in 1998 was 15% warmer than normal.

Gross profit in 1997 increased $15.0 million compared to 1996. This was primarily due to customer growth and normal weather in 1997. In 1996, winter weather was 8% warmer than normal.

OPERATING EXPENSES

Operating expenses decreased $5.1 million in 1998 compared to 1997. To recover from the effects of mild winter weather in the first quarter, we began a cost reduction program that reduced expenses by $15.7 million. This savings was partially offset by higher transmission fees and payroll and benefit increases.

Operating expenses increased $19.1 million in 1997 compared to 1996. This reflects inflation, greater allocation of expenses from Corporate, and increases in property taxes and depreciation from utility plant additions.

<TABLE>
<CAPTION>
SALES: REGULATED BUSINESS--ELECTRIC

<S>	<C>
98	616.6
97	557.4
96	519.3

0 200 400 600

DOLLARS IN MILLIONS
</TABLE>

In spite of mild weather and the Missouri electric rate decrease, Regulated Businesses increased its sales by 11% due to higher volumes sold outside its network area.

<TABLE>
<CAPTION>
SALES: REGULATED BUSINESS--GAS

<S>	<C>
98	622.5
97	767.4
96	727.9

0 200 400 600

DOLLARS IN MILLIONS

</TABLE>

The mild weather hurt gas sales during the first and fourth quarters of 1998, causing a sharp decrease in sales for the year.

<TABLE>
<CAPTION>
EBIT (NORMALIZED): REGULATED BUSINESSES

<S>	<C>
98	210.2
97	197.5
96	206.3

0 50 100 150 200

DOLLARS IN MILLIONS
</TABLE>

Normalized EBIT increased $12.7 million in 1998 due to strong growth in the number of customers and reduced expenses.

<TABLE>
<CAPTION>
CAPITAL EXPENDITURES: REGULATED BUSINESSES

<S>	<C>
98	101.8
97	116.6
96	112.8

0 25 50 75 100

DOLLARS IN MILLIONS
</TABLE>

Capital expenditures are made primarily to expand the system to serve a growing number of customers, and for maintenance.

AQUILA ENERGY

THREE-YEAR REVIEW--AQUILA ENERGY

<TABLE>
<CAPTION>

Dollars in millions	Year Ended December 31, 1998	1997	1996
<S>	<C>	<C>	<C>
SALES:			
Energy marketing	$ 9,692.7	$ 6,017.1	$ 1,882.4
Aquila Gas Pipeline	892.9	1,013.9	790.3
TOTAL SALES	10,585.6	7,031.0	2,672.7
COST OF SALES:			
Cost of energy marketing	9,569.3	5,909.0	1,822.6
Aquila Gas Pipeline	811.9	894.6	664.1
Total cost of sales	10,381.2	6,803.6	2,486.7
Gross profit	204.4	227.4	186.0
OPERATING EXPENSES:			
Operating and maintenance	132.1	121.0	107.7
Depreciation, depletion and amortization	27.7	27.6	28.6
Provision for asset impairments	17.2	15.5	--
Total operating expenses	177.0	164.1	136.3
Income from operations	27.4	63.3	49.7
Equity earnings in subsidiaries and partnerships	34.5	30.5	48.6
Minority interest expense and other	7.8	11.4	8.1
EARNINGS BEFORE INTEREST AND TAXES (EBIT)	54.1	82.4	90.2
NON-RECURRING ITEMS:			
Provision for asset impairments	17.2	15.5	--
Gain on sales lease of power project	--	--	(20.9)
NORMALIZED EBIT	$ 71.3	$ 97.9	$ 69.3
NORMALIZED EBIT CONTRIBUTION TO UTILICORP	20.5%	28.9%	21.9%
EBIT BY BUSINESS SUBUNIT:			
Energy marketing	$ 20.5	$ 18.4	$ (4.2)
Aquila Gas Pipeline	18.6	51.8	51.4
Independent power projects	32.2	27.7	22.1
TOTAL AQUILA ENERGY EBIT	$ 71.3	$ 97.9	$ 69.3
Identifiable assets	$ 2,290.9	$ 2,275.5	$ 1,900.1
Physical gas volumes marketed (billion cubic feet per day)	9.6	6.8	3.5
Gas throughput volumes(million cubic feet per day)	475	483	493
Natural gas liquids--price per gallon	$ .25	$ .34	$ .35
Natural gas liquids produced (thousand barrels per day)	25	37	41
Electricity marketing volumes (MWH 000's)	121,194	65,258	6,495

</TABLE>

<TABLE>
<CAPTION>
SALES: AQUILA ENERGY

<S>	<C>
98	10,585.6
97	7,031.0
96	2,672.7

0 2,000 4,000 6,000 8,000 10,000

DOLLARS IN MILLIONS
</TABLE>

Annual sales have increased nearly 300% since 1996. This is due to rapid growth in volumes and execution of our energy merchant strategy.

<TABLE>
<CAPTION>
EBIT (NORMALIZED): AQUILA ENERGY

<S>	<C>
98...	71.3
97...	97.9
96...	69.3

0 20 40 60 80

DOLLARS IN MILLIONS
</TABLE>

Normalized EBIT declined in 1998 due to a 26% decrease in prices for natural gas liquids (NGLs) and a 32% decrease in NGL volumes compared to 1997.

<TABLE>
<CAPTION>
CAPITAL EXPENDITURES: AQUILA ENERGY

<S>	<C>
98...	33.8
97...	28.4
96...	26.4

0 5 10 15 20 25 30

DOLLARS IN MILLIONS
</TABLE>

Capital expenditures primarily relate to line extensions for new well connections on the Aquila Gas Pipeline gathering system.

GROSS PROFIT

Gross profit in 1998 declined $23.0 million compared to 1997. The decrease reflects a $38.3 million drop in gross profit from Aquila Gas Pipeline (AQP) that was partially offset by a $15.3 million increase from Energy Marketing. AQP's results in 1998 were lower due to a 26% decrease in NGL prices and a 32% decrease in NGL production. This combination reduced AQP's 1998 gross profit by $25 million. NGL prices are closely tied to crude oil prices, which declined significantly in 1998. As oil prices declined, drilling activity in the Austin Chalk region of Texas, AQP's main gathering area, was limited to deep gas wells which produce less liquid. NGL production also declined because AQP voluntarily bypassed certain volumes due to low prices. The NGL price declines were largely shared with producers as a majority of AQP's contracts are structured as percent of production. We do not expect NGL prices or production to improve in 1999.

Gross profit from energy marketing increased 14% in 1998 compared to 1997, primarily due to the following:

- Increased gross margin from electricity, partially offset by lower gas marketing margins.
- An 86% increase in electricity marketing volumes as this market segment continued to expand.
- A 131% increase in gross margin from longer-term contracts (generally those of more than a year).
- Better results from commercial and industrial segments, achieved by increased focus on existing operations.

In June 1998, the price of electricity varied widely as the market reacted to a power shortage caused by several power plant outages and low reserve margins. During June, electricity prices fluctuated between $30 and $7,500 per megawatt-hour. This caused many market participants to panic as they covered open short positions with high-priced electricity. In addition, some firms did not honor their contract obligations, causing others to replace the lost electricity with higher-priced supply. We did not incur net losses from June's unusual pricing patterns. Assessing credit and counterparty risk is a cornerstone principle of our risk management system of internal control. This is why our credit policy is administered by a function that is independent from trading and sales.

Gross profit in 1997 increased $41.4 million or 22% compared to 1996. This was due to a 94% and 905% increase in gas and electricity marketing volumes which resulted in $26.2 million and $9.0 million, respectively, in additional margin. These volumetric increases reflect the impact of an aggressive expansion program.

Gross profit from AQP decreased $6.9 million in 1997 compared to 1996. NGL production volumes declined because of leaner gas streams, lower NGL prices and reduced gas marketing results. In 1997, NGL production volumes were down 10% and prices were down 3% compared to 1996. The leaner gas streams were due to generally deeper drilling in the Austin Chalk area.

Gross profit from small commercial and industrial gas marketing increased $13.1 million in 1997 over 1996 as these businesses were assimilated into Aquila from another business segment. The increase was due to the expansion of sales to industrial and commercial customers. In 1996, the retail business had fixed price sales contracts against variable purchase contracts when the price of natural gas escalated. Although the retail business improved in 1997, it still had a net EBIT loss of $5.1 million in 1997 compared to $13.1 million in 1996.

OPERATING EXPENSES

Operating expenses in 1998 were $11.2 million higher than in 1997, after normalizing for non-recurring items in both periods. Operating expenses increased primarily as a result of additional staffing needed to support the growth of the business.

Operating expenses increased $12.3 million in 1997 compared to 1996, after normalizing for the provision for asset impairment. The increase reflects higher staffing costs to support Aquila's aggressive growth strategy and rapid increase in marketing volumes.

EQUITY IN EARNINGS

Equity in earnings increased $4.0 million in 1998 compared to 1997, primarily because we sold part of our ownership in an independent power project for a $3.6 million gain. Equity in earnings increased $2.8 million in 1997 compared to 1996, after normalizing for the gain on sales lease of $20.9 million. The increase was primarily due to innovative gas tolling and dispatch arrangements at one of the independent power projects and increased production from another project.

<TABLE>
<CAPTION>
NGL PRICES PER GALLON
<S> <C>
98... 25
97... 34
96... 35
0 10 20 30

CENTS
</TABLE>

Prices for natural gas liquids declined by 26% in 1998 compared to 1997. Each $.01 change in price represents approximately $1.3 million in EBIT. The outlook for 1999 is no better than 1998.

<TABLE>
<CAPTION>
EBIT FROM LONG-TERM DEALS
<S> <C>
98... 57%
97... 20%
96... 14%*
0 10 20 30 40 50

PERCENT
</TABLE>

As Aquila's energy marketing business has expanded, total margins from longer term transactions have increased as a percentage of Aquila's total margins.

* Excludes retail EBIT.

INTERNATIONAL

The following table summarizes the company's International operations for the three years ended December 31, 1998.

THREE-YEAR REVIEW--INTERNATIONAL
<TABLE>

<CAPTION>

Dollars in millions	1998	1997	1996
	Year Ended December 31,		
SALES	$ 504.1	$ 305.2	$ 284.4
COST OF SALES	413.1	246.1	209.7
Gross profit	91.0	59.1	74.7
OPERATING EXPENSES:			
Other operating	40.5	21.6	24.8
Maintenance	4.2	10.0	9.0
Taxes, other than income taxes	12.1	11.3	12.2
Depreciation and amortization	13.0	11.0	12.5
Total expense	69.8	53.9	58.5
Income from operations	21.2	5.2	16.2
Equity earnings in subsidiaries and partnerships	88.5	42.3	60.1
Other income (expense)	(5.9)	5.0	3.4
EARNINGS BEFORE INTEREST AND TAXES (EBIT)	103.8	52.5	79.7
NON-RECURRING ITEMS:			
Reserve for United Kingdom gas contracts	--	5.0	--
United Energy initial public offering	(45.3)	--	--
National Power interest charge	6.8	--	--
Midlands Gas contract settlement	6.6	--	--
NORMALIZED EBIT	$ 71.9	$ 57.5	$ 79.7
NORMALIZED EBIT CONTRIBUTION TO UTILICORP	20.8%	17.0%	25.2%
CUSTOMERS:			
Australia	546,000	540,000	530,000
Canada	132,000	131,000	129,000
New Zealand (a)	468,000	282,000	276,000
United Kingdom	1,011,000	97,000	48,000
TOTAL CUSTOMERS	2,157,000	1,050,000	983,000
Identifiable assets	$ 1,437.0	$ 789.0	$ 848.3

</TABLE>

(a) Customer count for 1998 includes indirect customers from the TrustPower transaction that closed in January 1999.

SUMMARY

International normalized EBIT consists of operations and equity investments in the following countries for the three years ended December 31, 1998.

<TABLE>
<CAPTION>

In millions	1998	1997	1996
Australia	$ 22.3	$ 27.0	$ 38.3
Canada	22.0	26.2	27.7
New Zealand	21.4	9.9	11.6
United Kingdom	6.2	(5.6)	2.1
TOTAL	$ 71.9	$ 57.5	$ 79.7

</TABLE>

The normalized EBIT by country is discussed below.

GROSS PROFIT

International gross profit increased $31.9 million in 1998 compared to 1997. This increase is primarily due to the consolidation of UnitedNetworks, beginning in October 1998, because of our increased level of ownership. Gross profit from UnitedNetworks was $23.8 million. Prior to October 1998, our New Zealand investments were accounted for under the equity method and shown in "Equity earnings in subsidiaries and partnerships." Gross profit from the United Kingdom (U.K.) increased $14.8 million in 1998 after adjusting for non-recurring items. This is due to an increase in trading and transportation margin resulting from the execution of our wholesale services strategy. Our indirect customers in the U.K. increased from 97,000 to more than 1 million in 1998. We bought out two above-market gas supply contracts in 1998 for $25.6 million. The contracts had hampered profitability in the 1998 first quarter and in 1997. A reserve we set up in advance covered $19.0 million of this amount.

Gross profit from Canada was down $5.2 million in 1998 compared to 1997 due to milder winter weather and higher power costs.

United Kingdom gross profit was $7.2 million lower in 1997 compared to 1996, after adjusting for non-recurring items. This mainly reflects two high-cost gas supply contracts that took effect in October 1996.

OPERATING EXPENSES

Operating expenses increased $15.9 million in 1998 compared to 1997. This was due to a $15.8 million increase from New Zealand related to the consolidation of UnitedNetworks in October 1998.

Operating expenses in 1997 were $4.6 million lower than in 1996 due to higher currency values in most of our foreign markets in 1996 and higher expatriate expenses in 1996 due to initial relocation costs.

Initial Public Offering--United Energy Limited

In May 1998, United Energy Limited (UEL) sold 42% of its common stock to the public. As a result, we recorded a $45.3 million gain. Also, our ownership percentage in UEL reduced from 49.9% to 29%. Concurrent with UEL's stock offering, we bought an additional 5% in UEL from another company. Prior to the common stock sale, UEL repaid approximately $101 million in debt notes. The effect of this transaction reduced our ownership position, but was substantially offset by higher earnings at UEL as a result of lower interest costs and application of the $101 million to reduce our debt.

COMPETITION IN AUSTRALIA

The State of Victoria is deregulating its electricity market in stages. Currently, customers with yearly usage above 160 megawatt-hours (industrial and large commercial customers) can choose their retail electricity suppliers. After January 1, 2001, all UEL customers will be able to choose their retail electricity suppliers. A majority of UEL's gross margin comes from distribution line charges that would not be affected by this customer choice.

NEW ZEALAND ACQUISITIONS AND DISPOSITIONS

In 1998, through a series of transactions we gained control of Power New Zealand Limited (PNZ) through the purchase of an additional 48% interest. We bought the additional 48% for $245 million, bringing our total ownership interest in PNZ to 79%.

As part of New Zealand's Electricity Industry Reform Act of 1998, electric companies were required to separate the ownership of their lines (distribution) and supply (generation and retail) businesses and choose to become either a lines company or a supply company. This requires selling any other piece of the business not in the chosen segment. PNZ decided to become a lines company and as a result, it has sold its retail business to TransAlta New Zealand Ltd. In addition, PNZ bought TransAlta's lines business, paying a net $238 million after the two transactions. PNZ also acquired a lines business from TrustPower for $261 million, effective January 1999. As part of the sale of PNZ's retail business, PNZ sold the Power New Zealand name to TransAlta. Our network business in New Zealand is now known as UnitedNetworks Limited. We expect that all of these transactions will increase the EBIT contribution from New Zealand by $55 million in 1999 compared to 1998.

<TABLE>
<CAPTION>
SALES: INTERNATIONAL

<S>	<C>
98	504.1
97	305.2
96	284.4

0 100 200 300 400 500

DOLLARS IN MILLIONS
</TABLE>

Sales in 1998 increased 65% over 1997 due to a sharp increase in customers in the U.K. and increased ownership in our New Zealand businesses.

<TABLE>
<CAPTION>

CAPITAL EXPENDITURES: INTERNATIONAL

<S> <C>

98	20.0
97	19.4
96	21.5

0 5 10 15 20

DOLLARS IN MILLIONS

</TABLE>

Capital expenditures primarily relate to the expansion of our Canadian electric system and construction of a gas storage facility in the U.K.

<TABLE>
<CAPTION>

EBIT (NORMALIZED): INTERNATIONAL

<S> <C>

98	71.9
97	57.5
96	79.7

0 20 40 60

DOLLARS IN MILLIONS

</TABLE>

Normalized EBIT increased by $14.4 million in 1998 due to strong growth in the U.K. and New Zealand as we executed our growth initiatives.

CORPORATE MATTERS

CORPORATE AND OTHER

The table below summarizes the corporate and other EBIT for the three years ended December 31, 1998. Corporate primarily contains the retained costs of the company that are not allocated to the business units and the net losses from the company's investment in EnergyOne, L.L.C.

<TABLE>
<CAPTION>

In millions	1998	1997	1996
<S>	<C>	<C>	<C>
EBIT, as reported	$ (14.2)	$ 26.6	$ (50.0)
Merger termination	--	(53.0)	11.0
Asset impairment provision	8.0	11.0	--
Other	--	1.6	--
Normalized EBIT	$ (6.2)	$ (13.8)	$ (39.0)

</TABLE>

Corporate and other normalized EBIT increased by $7.6 million due to the elimination of losses from our EnergyOne partnership with PECO Energy Company. The partnership was terminated in April 1998. Corporate and other normalized EBIT improved by $25.2 million in 1997 compared to 1996 due to the elimination of certain corporate activities and transfer of capital costs associated with new information systems recorded at corporate, but allocated to business units.

COMPETITION

DOMESTIC UTILITY OPERATIONS. Our domestic utility businesses operate in a regulated environment despite various legislative efforts at the federal level. Industrial and large commercial customers largely have access to energy sources so some of the competitive pricing benefits have been transferred to these customers through open access tariffs relating to transmission lines and pipelines. Without federal legislation, competition at the retail level cannot form since the rules will be different in each state. As a result of our assessment of retail competition possibilities, we reduced most retail activities until the market more fully develops.

ACCOUNTING IMPLICATIONS. We currently record the economic effects of regulation in accordance with the provisions of Statement of Financial Accounting Standards No. 71 (SFAS No. 71), "Accounting for the Effects of Certain Types of Regulation," and accordingly our balance sheet reflects certain costs as regulatory assets. We expect that our rates will continue to be based on historical costs for the foreseeable future. If we discontinued applying SFAS No. 71, we would make adjustments to the carrying value of our regulatory assets. Total net regulatory assets at December 31, 1998 were $96.5 million.

ENERGY MARKETING. Our energy marketing businesses operate in a fully competitive environment that rewards participants on price, service and execution. Our energy marketing businesses compete for customers with some of the largest utility and energy companies in North America. The industry is premised on large volume sales with relatively low margins. Companies that operate in this industry must fully understand the price sensitivity and volatility of commodities. The public became more aware of some of the risks associated with this industry when a number of companies announced sudden losses resulting from the June price spike in electricity. We expect price volatility and we expect events like the June price spike to recur.

ENVIRONMENTAL MATTERS

We have been named a potentially responsible party (PRP) at three PCB disposal facilities. Our combined cleanup expenditures have been less than $1 million to date. We anticipate that future expenditures on these sites will not be significant.

We also own or once operated 29 former manufactured gas plants which may require some form of environmental remediation. See Note 15 to the Consolidated Financial Statements for further discussion of this topic.

In December 1996, the EPA published its final rule for nitrous oxide (NOx) emissions under the requirements of the Clean Air Act Amendments of 1990. The new NOx regulations will affect one of our power plants by requiring us to install additional emissions controls by January 1, 2000. In October 1998, the EPA published new air quality standards to further reduce the emission of NOx. These more strict standards will require us to install new equipment on our baseload coal units in Missouri that we estimate will cost $35 million. The ultimate cost is under debate and subject to change. The new standards as written are effective in May 2003.

YEAR 2000 ISSUES

Our computer systems as presently configured may not recognize the two-digit date of "00" as the year 2000. This could cause systems to shut down or malfunction. In order to address potential year 2000 issues, we established a Year 2000 Project Office to coordinate efforts in our operating units to ensure that computer systems and applications will function properly beyond 1999.

Many of our information systems and related software are already year 2000-ready. We have installed a major new software system that includes financial, customer information (in certain locations) and support systems. We also expect to have our new customer information system fully installed by mid-1999. We expect these projects, known internally as "Project BTU," to replace at least 80% of potentially affected software. We began Project BTU in 1995 to update our internal support systems and position us to serve our customers better. Total expenditures for the new systems will be approximately $186.0 million. Of this amount, to date we have spent $143.9 million.

We are also coordinating the identification and testing of remaining software, information technology devices, embedded technology systems, and services provided by third parties that may be affected by the year 2000. We completed the identification and testing phases in 1998 and will begin remediation in 1999. At this time, we do not have a contingency plan to address unforeseen issues, but we expect the Project Office to have one by mid-1999. We are currently preparing budgets and estimates of

remediation costs for this portion of our year 2000 remediation of mission-critical systems. We expect the remediation of certain non-mission-critical systems to extend beyond 1999. We expect to spend approximately $2.3 million in total remediation costs outside of Project BTU.

We are evaluating the impact of internal and external year 2000 issues on our operations to develop a model on which to base contingency planning. We are conducting internal evaluations and discussions with other utilities, as well as participating in industry-wide efforts being conducted by the North American Electric Reliability Council and the Gas Industry Standards Board, to prepare for this issue and ensure the company's efforts are in line with the rest of the industry.

For complete system changeouts, we capitalize cost under guidelines described in Emerging Issues Task Force (EITF) 97-13, "Accounting for Costs Incurred in Connection with a Consulting Contract or an Internal Project that Combines Business Process Reengineering and Information Technology Transformation." For programming fixes on existing systems, we record these costs as maintenance expense.

MARKET RISK--TRADING

We are exposed to market risk, including changes in commodity prices, interest rates and currency exchange rates. To manage the volatility relating to these exposures, we enter into various derivative transactions in accordance with our policy approved by the Board of Directors. We routinely enter into financial instrument contracts to position the portfolio. Our trading portfolios consist of physical and financial natural gas, electricity, coal and interest rate contracts. These contracts take many forms including futures, forwards, swaps and options.

We measure the risk in our trading portfolio using value-at-risk methodologies, to simulate forward price curves in the energy markets and estimate the size of future potential losses. The quantification of market risk using value-at-risk methodologies provides a consistent measure of risk across diverse energy markets and products. The use of this method requires a number of key assumptions, such as:

- Selection of a confidence level (we use 95%).

- Estimated holding period (we use three days).

- Use of historical estimates of volatility and correlation with recent activity more heavily weighted.

At December 31, 1998, our value at risk was:

<TABLE>
<CAPTION>

In millions	
Electricity	$ .7
Natural gas	2.2

</TABLE>

The average value at risk for all commodities during 1998 was $3.8 million.

We also use additional risk control mechanisms such as stress testing, daily loss limits and commodity position limits, as well as daily monitoring of the trading activities by an independent function.

Although interest and foreign currency risks are monitored within the commodity portfolios and value-at-risk calculation, separate portfolios for interest and foreign currency risks do not exist. The value of our commodity portfolios are impacted by interest rates as the portfolio is valued using an estimated interest discount factor to December 31, 1998. We often sell Canadian sourced natural gas into the U.S. markets accepting U.S. dollars from customers, but paying Canadian dollars to suppliers. This exposes our portfolio to currency risk. We currently do not hedge this exposure.

The table below shows the expected cash flows associated with the interest rate financial instruments at December 31, 1998.

<TABLE>
<CAPTION>

Dollars in millions	1999	2000	2001	2002	2003	Thereafter	Total
Variable to fixed rate	$ 1.6	--	--	--	--	--	$ 1.6
Average rate paid	5.28%	--	--	--	--	--	
Average rate received	5.36%	--	--	--	--	--	
Fixed to variable rate	--	--	$(3.6)	--	$(1.2)	$(1.1)	$(5.9)
Average rate paid	--	--	7.36%	--	6.80%	6.71%	
Average rate received	--	--	3.81%	--	4.46%	5.64%	

</TABLE>

MARKET RISK--NON-TRADING

We are also exposed to commodity price changes outside of price risk management activities. The following table summarizes these exposures on an EBIT basis.

<TABLE>

<CAPTION>

	Commodity Price Change	EBIT Impact (a)
<S>	<C>	<C>
NGL price per gallon	+/- $.01	$1.3 million
Natural gas price per MCF	+/- $.10	.3 million
United Kingdom natural gas prices	+/- $.01	1.3 million

</TABLE>

(a) Assumes the price change occurs for an entire year. For the U.K., the price change assumes that it occurs over the entire forward contract period.

CURRENCY RATE EXPOSURE

We do not currently hedge our net investment in foreign operations. As a result, the foreign denominated assets and liabilities fluctuate in value. Historically, our net exposure to changes in foreign currency has been limited as the company's foreign investments were financed through foreign debt.

The table below summarizes the average value of foreign currencies used to value sales and expenses along with the related sensitivity.

<TABLE>
<CAPTION>

	EBIT Impact of 10% change (a)	Unit Value in U.S. Dollars 1998	1997	1996
<S>	<C>	<C>	<C>	<C>
Australian dollar	+ $2.2 million	$ .63	$ .74	$ .78
Canadian dollar	+ 2.2 million	.67	.72	.73
New Zealand dollar	+ 2.1 million	.54	.66	.69
British pound	+ .6 million	1.66	1.65	1.53
Total	+ $7.1 million			

</TABLE>

(a) Assuming a 10% change in local currency value relative to the U.S. dollar if the change occurred uniformly over the entire year, based on 1998 financial results.

INTEREST RATE EXPOSURE

We have approximately $446.5 million of variable rate debt as of December 31, 1998. A 100-basis-point change in each debt's benchmark rate would affect net income by approximately $2.7 million. We hedged approximately $316 million of variable debt with fixed rate financial instruments.

LIQUIDITY AND CAPITAL RESOURCES

Our cash requirements arise primarily from continued growth, electric and gas utility construction programs, non-regulated investment opportunities and Aquila Energy's working capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall plan. Historically, we have financed acquisitions and investments initially with short-term debt and subsequently funded them with an appropriate mix of common equity and long-term debt securities, depending on prevailing market conditions.

A primary source of short-term cash has been bank loans which aggregated $235.6 million, $113.8 million and $202.0 million at December 31, 1998, 1997 and 1996, respectively. We can also issue up to $150 million of commercial paper supported by a $250 million committed revolving credit agreement. The credit agreement expires in December 2000 and allows for the issuance of notes at interest rates based on various money market rates. We had no commercial paper borrowings at December 31, 1998 and 1997.

To maintain flexibility in our capital structure and to take advantage of favorable short-term rates, we sell our accounts receivable under two programs to fund a portion of our short-term cash requirements. The level of funding available from these programs is limited to $280 million and the amount fluctuates seasonally. We had sold approximately $248 million under these programs at December 31, 1998. These programs were fully utilized at December 31, 1997 and 1996.

In 1998, certain customers prepaid $185.2 million for future gas supplies. We used this cash to reduce short-term debt. In the future we will incur short-term debt to buy gas over the contract period.

In 1998 we sold 12.98 million shares of our common stock at $23.41 per share, net of underwriting costs. The $304 million in net proceeds was used to reduce domestic short-term debt and accounts receivable sales programs. Our capital structure consisted of the following components at December 31, 1998 and 1997.

	1998	1997
Common stock equity	42.5%	40.3%
Monthly income preferred stocks	2.9	3.5
Short-term debt	6.9	3.9
Long-term debt	47.7	52.3
Total Capitalization	100.0%	100.0%

We have approximately 2.2 million treasury shares as of December 31, 1998, that we expect to issue to our stock plans in 1999. Our dividend payout ratio was 73% in 1998 (annualized dividends of $1.20 divided by basic EPS of $1.65). We expect our EPS growth to be approximately four times our dividend growth. This should reduce our payout ratio to about 50-60% over the next five years. The combination of higher earnings growth compared to dividends and the expected reissue of treasury stock will increase the equity component in our capital structure in the future.

CASH REQUIREMENTS

Future cash requirements include utility plant additions, required redemptions of long-term securities, and acquisition opportunities. We estimate expenditures over the next three years for these activities, excluding acquisitions, will be as follows:

	Actual	Future Cash Requirements		
In millions	1998	1999	2000	2001
Regulated Businesses	$101.8	$118.0	$113.0	$115.0
Aquila Energy	33.8	25.0	130.0	161.0
International	20.0	32.0	31.0	27.0
Maturing long-term debt	216.4	248.8	164.5	44.4
Other	48.7	55.0	42.0	23.0
Total	$420.7	$478.8	$480.5	$370.4

Aquila Energy plans to build a 500-megawatt combined cycle generation plant, initially to serve the capacity needs of our Regulated Businesses beginning in June 2001. The new plant is expected to cost approximately $241 million.

We expect to refinance our maturing debt issues in 1999 and will consider refinancing or restructuring certain higher coupon debt in 1999 if market conditions warrant. We believe that our available cash resources from both operating cash flows and borrowing capacity will be adequate to meet our anticipated future cash requirements.

SIGNIFICANT BALANCE SHEET MOVEMENTS

Total assets increased $878 million in 1998 compared to 1997. This increase is primarily due to the following:

- We invested approximately $609.7 million in New Zealand in 1998 to obtain control of UnitedNetworks, at the time transitioning to become a lines business, and to acquire an additional lines business. The increase also reflects the buyout of a partner in Australia.

- Assets of the company reflect UnitedNetworks on a consolidated basis for 1998, versus as an equity investment in 1997.

- We purchased 47 Bcf of gas held in storage at December 31, 1998 that will be used in Aquila's gas marketing business.

- Price risk management assets (current and long-term) increased $105.6 million, reflecting the expansion of Aquila's business in 1998.

Total liabilities increased in 1998 by $595.3 million and common shareowners' equity increased by $282.7 million in 1998 due to the following:

- Long-term debt increased by $116.4 million in 1998 due primarily to the acquisition activity in New Zealand, partially offset by maturing debt and the application of $101 million against debt that we received from UEL.

- Short-term debt increased $121.8 million in 1998 due to the acquisition activity in New Zealand.

- Minority interests increased by $92.6 million in 1998 due to New Zealand acquisition activity.

- Price risk management liabilities increased $206.4 million, reflecting the expansion of Aquila's business in 1998.

- Common shareowners' equity increased by $282.7 million due to the sale of 12.98 million common shares, partially offset by treasury shares held.

AQUILA GAS PIPELINE BUYOUT PROPOSAL

In November 1998, we made a proposal to acquire the 18% of AQP's common stock we do not already own for $8.00 per share. An independent committee of AQP'S Board of Directors is evaluating the proposal.

NEW ACCOUNTING STANDARDS

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). SFAS 133 established accounting and reporting standards for derivative instruments and hedging activities requiring that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded in the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that the company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133 must be adopted for fiscal years beginning after June 15, 1999.

SFAS 133 will impact our hedging activities at Aquila Energy and Aquila Gas Pipeline, corporate treasury activities, foreign subsidiary trading activities, and power trading contracts. We have not quantified this impact.

In 1998 the Emerging Issues Task Force (EITF) agreed to require companies to mark to market their energy trading activities beginning in 1999. We already use the mark-to-market method of accounting for domestic trading activities. However, we engage in certain trading activities internationally for which we do not use mark-to-market accounting. We are evaluating the impact this will have on our financial results. At this time we cannot estimate that impact.

EFFECTS OF INFLATION

In the next few years, the company anticipates that the level of inflation, if moderate, will not have a significant effect on operations or acquisition activity.

FORWARD-LOOKING INFORMATION

This report contains forward-looking information. Such statements involve risks and uncertainties and there are certain important factors that could cause actual results to differ materially from those anticipated. Some of the important factors which could cause actual results to differ materially from those anticipated include:

- Weather, which can affect results significantly to the extent that temperatures differ from normal. Both our utility and energy merchant businesses are weather-sensitive.

- The timing and extent of changes in energy commodity prices and interest rates.

- The pace and degree of regulatory changes in the U.S. and abroad.

- NGL prices and volumes, which are particularly volatile and difficult to predict.

- The pace of well connections to our gathering system.

- The value of the U.S. dollar relative to the British pound, Canadian dollar, Australian dollar and New Zealand dollar.

- The continued expansion of the electric power markets and development of liquid term markets.

- Pending rate proceedings.

CASH FROM OPERATIONS

98	276.8
97	349.0
96	262.8

0 100 200 300

DOLLARS IN MILLIONS

Cash from operations funds our normal capital expenditures and our dividend requirements.

UTILITY PLANT ADDITIONS

98	121.8
97	133.2
96	134.3

0 25 50 75 100 125

DOLLARS IN MILLIONS

Total utility plant additions have remained relatively constant since 1996. Our capital expenditures have been made to serve new customers and to replace utility plant.

A UtiliCorp United Company

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
In millions except per share	1998	1997	1996
SALES	$ 12,563.4	$ 8,926.3	$ 4,332.3
Cost of sales	11,596.0	7,972.0	3,420.3
GROSS PROFIT	967.4	954.3	912.0

Operating, administrative and maintenance expense	548.9	554.9	549.8
Depreciation, depletion, and amortization	150.0	129.6	125.4
Provision for asset impairments	27.7	26.5	--
Write-off of deferred merger costs, net of termination fee received	--	--	11.0
INCOME FROM OPERATIONS	240.8	243.3	225.8
OTHER INCOME (EXPENSE):			
Equity in earnings of investments and partnerships	125.1	68.8	108.7
Minority interests	(5.6)	(6.5)	(8.0)
Merger termination fee	--	53.0	--
Other income (expense)	(8.9)	.5	(.3)
TOTAL OTHER INCOME	110.6	115.8	100.4
EARNINGS BEFORE INTEREST AND TAXES	351.4	359.1	326.2
INTEREST EXPENSE:			
Interest expense long-term debt	111.4	115.5	118.0
Interest expense short-term debt	12.3	10.9	12.8
Minority interest in income of partnership	8.9	8.9	8.9
TOTAL INTEREST EXPENSE	132.6	135.3	139.7
EARNINGS BEFORE INCOME TAXES	218.8	223.8	186.5
Income taxes	86.6	89.7	80.7
EARNINGS BEFORE EXTRAORDINARY ITEM AND CUMULATIVE EFFECT OF SOFTWARE ACCOUNTING CHANGE	132.2	134.1	105.8
Loss on retirement of debt (net of income tax of $4.5)	--	7.2	--
Cumulative effect of software accounting change (net of income tax of $3.2)	--	4.8	--
Net income	132.2	122.1	105.8
Preference dividends	--	.3	2.1
EARNINGS AVAILABLE FOR COMMON SHARES	$ 132.2	$ 121.8	$ 103.7
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	80.07	80.42	70.81
Diluted	81.18	81.00	71.29
EARNINGS PER COMMON SHARE:			
Basic	$ 1.65	$ 1.51	$ 1.46
Diluted	1.63	1.51	1.46

</TABLE>

ALL SHARE AND PER SHARE AMOUNTS HAVE BEEN RESTATED FOR THE 3-FOR-2 STOCK SPLIT.

SEE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

[GRAPHIC]

<TABLE>
<CAPTION>
SALES GROWTH -- AQUILA AND TOTAL

<S>	<C>
Aquila	10.6
98 Total	12.6
Aquila	7.0
97 Total	8.9
Aquila	2.7
96 Total	4.3
0 4 8 12	

DOLLARS IN BILLIONS
</TABLE>

Annual sales have increased by $8.3 billion or 190% since 1996, primarily due to rapid growth at Aquila Energy.

CONSOLIDATED BALANCE SHEETS

<TABLE>
<CAPTION>

Dollars in millions	Year Ended December 31, 1998	1997
<S>	<C>	<C>
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 120.5	$ 89.5
Funds on deposit	13.4	31.5
Accounts receivable, net	1,137.5	1,165.1
Inventories and supplies	235.1	111.6
Price risk management assets	173.1	121.5
Prepayments and other	85.8	95.2
TOTAL CURRENT ASSETS	1,765.4	1,614.4
Property, plant and equipment, net	3,313.9	2,480.3
Investments in subsidiaries and partnerships	519.8	691.2
Price risk management assets	215.5	161.5
Deferred charges	176.9	166.1
TOTAL ASSETS	$ 5,991.5	$ 5,113.5
LIABILITIES AND SHAREOWNERS' EQUITY		
CURRENT LIABILITIES:		
Current maturities of long-term debt	$ 248.8	$ 149.6
Short-term debt	235.6	113.8
Accounts payable	1,275.9	1,356.3
Accrued liabilities	50.6	13.8
Price risk management liabilities	192.2	123.7
Other	89.6	52.7
TOTAL CURRENT LIABILITIES	2,092.7	1,809.9
LONG-TERM LIABILITIES:		
Long-term debt, net	1,375.8	1,358.6
Deferred income taxes and credits	429.5	362.7
Price risk management liabilities	308.4	170.5
Minority interests	151.6	59.0
Other deferred credits	87.2	89.2
TOTAL LONG-TERM LIABILITIES	2,352.5	2,040.0
Company-obligated mandatorily redeemable preferred securities of partnership	100.0	100.0
Common shareowners' equity	1,446.3	1,163.6
Commitments and contingencies		
TOTAL LIABILITIES AND SHAREOWNERS' EQUITY	$ 5,991.5	$ 5,113.5

</TABLE>

SEE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

<TABLE>
<CAPTION>
FOREIGN ASSETS AT YEAR END

<S>	<C>
98	1,655.0
97	907.9
96	940.9
95	712.1
94	295.4

0 500 1,000 1,500

DOLLARS IN MILLIONS
</TABLE>

International asset growth in 1998 primarily reflects acquisitions in New Zealand. We invested an additional $261 million there in January 1999.

<TABLE>
<CAPTION>
EQUITY RATIO

<S>	<C>
98	42.5%
97	40.3%
96	38.2%

0 10 20 30 40

PERCENT
</TABLE>

Our equity ratio improved in 1998 due to the common stock offering in December 1998. We expect our equity ratio to be about 40% in 1999.

CONSOLIDATED STATEMENTS OF COMMON SHAREOWNER'S EQUITY

<TABLE>
<CAPTION>

Dollars in millions except per share	1998	1997	1996
<S>	<C>	<C>	<C>
COMMON STOCK: authorized 200,000,000 shares, par value $1 per share, 93,574,853 shares outstanding (80,630,700 at December 31, 1997 and 79,940,468 at December 31, 1996); authorized 20,000,000 shares of Class A common stock, par value $1 per share, none issued			
Balance beginning of year	$ 80.6	$ 79.9	$ 69.0
Issuance of common stock	13.0	.7	10.9
BALANCE END OF YEAR	93.6	80.6	79.9
PREMIUM ON CAPITAL STOCK:			
Balance beginning of year	972.3	965.1	777.6
Issuance of common stock	290.7	7.2	187.5
Other	(9.5)	--	--
BALANCE END OF YEAR	1,253.5	972.3	965.1
RETAINED EARNINGS:			
Balance beginning of year	152.8	125.3	106.2
Net income	132.2	122.1	105.8
Dividends on preference stock	--	(.3)	(2.1)
Dividends on common stock, $1.20 per share in 1998, $1.17 in 1997, and $1.17 in 1996	(95.0)	(94.3)	(84.6)
BALANCE END OF YEAR	190.0	152.8	125.3
Treasury stock, at cost (2,159,330 shares at December 31, 1998, 352,613 shares at December 31, 1997 and 343,211 shares at December 31, 1996)	(53.2)	(10.8)	(6.4)
Currency translation adjustment	(37.6)	(31.3)	(5.9)
TOTAL COMMON SHAREOWNERS' EQUITY	$ 1,446.3	$ 1,163.6	$ 1,158.0

Year Ended December 31 (all columns).

</TABLE>

ALL SHARE AND PER SHARE AMOUNTS HAVE BEEN RESTATED FOR THE 3-FOR-2 STOCK SPLIT.

SEE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

<TABLE>
<CAPTION>

	Year Ended December 31,		
Dollars in millions	1998	1997	1996
<S>	<C>	<C>	<C>
Net income	$ 132.2	$ 122.1	$ 105.8
Unrealized translation adjustments	(6.3)	(25.4)	.5
COMPREHENSIVE INCOME	$ 125.9	$ 96.7	$ 106.3

</TABLE>

SEE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

CONSOLIDATED STATEMENTS OF CASH FLOWS

<TABLE>
<CAPTION>

	Year Ended December 31,		
Dollars in millions	1998	1997	1996

<S> <C> <C> <C>

CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$132.2	$122.1	$105.8
Adjustments to reconcile net income to net cash provided:			
Depreciation, depletion and amortization	150.0	129.6	125.4
Provision for asset impairments	27.7	26.5	--
Net changes in price risk management assets and liabilities	100.8	84.3	(33.7)
Deferred taxes and investment tax credits	61.7	49.0	34.5
Equity in earnings from investments and partnerships	(125.1)	(68.8)	(108.7)
Dividends from investments and partnerships	48.9	36.0	42.7
Minority interests	5.6	6.5	8.0
Write-off of deferred merger costs, net of termination fee received	--	--	11.0
Loss on retirement of debt, net	--	7.2	--
Cumulative effect of software accounting change, net	--	4.8	--
Changes in certain assets and liabilities, net of effects of acquisitions and restructuring			
Accounts receivable, net	64.7	(385.6)	(506.2)
Accounts receivable sold	(32.0)	50.0	61.6
Inventories and supplies	(100.5)	(.7)	1.6
Prepayments and other	(13.6)	(27.4)	(14.8)
Accounts payable	(101.9)	408.5	513.5
Accrued liabilities, net	36.8	(28.5)	15.2
Other	21.5	(64.5)	6.9
CASH PROVIDED FROM OPERATING ACTIVITIES	276.8	349.0	262.8
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	(121.8)	(133.2)	(134.3)
Purchase of utility and other business	--	--	(138.1)
Investments in international businesses	(520.0)	(2.8)	(42.3)
Redemption of investment in debt securities	101.1	--	--
Investments in energy related properties	(33.8)	(28.4)	(26.4)
Other	(.6)	(38.2)	(70.5)
CASH USED FOR INVESTING ACTIVITIES	(575.1)	(202.6)	(411.6)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	303.7	7.9	198.4
Retirement of preference stock	--	(25.0)	--
Treasury stock acquired	(42.3)	(4.4)	(6.4)
Issuance of long-term debt	267.0	169.0	129.7
Retirement of long-term debt	(216.4)	(108.7)	(22.2)
Short-term borrowings (repayments), net	121.8	(138.2)	(37.6)
Cash dividends paid	(95.0)	(94.6)	(86.7)
Other	(9.5)	--	--
CASH PROVIDED FROM (USED FOR)FINANCING ACTIVITIES	329.3	(194.0)	175.2
Increase (decrease) in cash and cash equivalents	31.0	(47.6)	26.4
Cash and cash equivalents at beginning of year	89.5	137.1	110.7
CASH AND CASH EQUIVALENTS AT END OF YEAR	$120.5	$ 89.5	$137.1

</TABLE>

SEE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS.

NOTE 1:

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NATURE OF OPERATIONS

UtiliCorp United Inc. is an international energy and energy solutions provider headquartered in Kansas City, Missouri. We operate lines of business in the following financial reporting segments: Regulated Businesses and Aquila Energy (Aquila). Through locally based managements we operate our international businesses as stand-alone companies or investments. Together these comprise the International segment.

The main activity of Regulated Businesses is operating domestic utilities that distribute and transmit electricity and natural gas. Our generation facilities produce electricity in the U.S., primarily for our own distribution system. We sell the rest of the output outside our service areas. We also provide appliance maintenance and repair and market natural gas. Aquila markets wholesale energy, gathers, transports and processes natural gas and gas liquids, and holds interests in independent power projects. Aquila Energy Corporation is a wholly-owned subsidiary of UtiliCorp. Aquila Gas Pipeline Corporation (AGP), 82%-owned by Aquila, operates the gas gathering and processing businesses, located in Texas and Oklahoma.

Our utilities are in eight states, one Canadian province and New Zealand. We market natural gas and electricity throughout the U.S. and in parts of Canada, and market natural gas in the United Kingdom (U.K.). We also have various investments in Australia and Jamaica.

USE OF ESTIMATES

We prepared these financial statements in conformity with generally accepted accounting principles and made certain estimates and assumptions that affect the reported amounts of assets and liabilities. Our estimates and assumptions affect the disclosure of contingent assets and liabilities in this report and reported amounts of sales and expenses during the reporting period. Actual results could differ from those estimates. Our accounting policies conform to generally accepted accounting principles.

PRINCIPLES OF CONSOLIDATION

Our consolidated financial statements include all of UtiliCorps operating divisions and majority-owned subsidiaries. We use equity accounting for investments of which we own between 20% and 50%. We eliminate any significant inter-company accounts and transactions.

PROPERTY, PLANT AND EQUIPMENT

We show property, plant and equipment at cost. We expense repair and maintenance costs as incurred. Depreciation is provided on a straight-line basis over the estimated lives for utility plant by applying composite average annual rates. These range from 2.1% to 4.2%, as approved by regulatory authorities. When property is replaced, removed or abandoned, its cost, together with the costs of removal less salvage, is charged to accumulated depreciation. We depreciate gathering, processing and other energy related property using a composite average annual rate of 4.0%. We depreciate remaining non-regulated property, plant and equipment on a straight-line basis over their estimated lives, ranging from three to 50 years.

SALES RECOGNITION

We recognize sales as products and services are delivered, except for trading and energy marketing activities. These are discussed below.

For North American trading and energy marketing activities, we use the mark-to-market method of accounting. Under that method, trading and energy marketing activities are recorded at fair value, net of future servicing costs and reserves. When the portfolio's market value changes (primarily due to newly originated transactions and the effect of price changes) the change is recognized as gains or losses in the period of change within the sales caption. We record the resulting unrealized gains and losses as price risk management assets and liabilities.

INCOME TAXES

Our financial statements use the liability method to reflect income taxes. To estimate deferred tax assets and liabilities we apply current tax regulations at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. We amortize deferred investment tax credits over the lives of the related properties.

CASH EQUIVALENTS AND CASH FLOW INFORMATION

Cash includes cash in banks and temporary investments with an original maturity of three months or less. As of December 31, 1998, 1997 and 1996, our cash held in foreign countries was $41.7 million, $74.5 million and $86.7 million, respectively.

Cash payments for interest, taxes and supplemental disclosures relating to acquisition activities are presented below:

<TABLE>
<CAPTION>

In millions	1998	1997	1996
<S>	<C>	<C>	<C>
Cash paid during the year for:			
Interest, net of amount capitalized	$132.4	$131.4	$132.1
Income taxes	50.1	61.9	49.1
Liabilities assumed in acquisitions:			
Fair value of assets acquired	$609.7	$ --	$ 7.0
Cash paid for acquisitions	520.0	--	--
Liabilities assumed	89.7	--	7.0

</TABLE>

EARNINGS PER COMMON SHARE*

The table below shows how we calculated diluted earnings per share and diluted shares outstanding. Basic earnings per share and basic weighted average shares are the starting point in calculating the dilutive measures. To calculate basic earnings per share, divide earnings available into weighted average shares without adjusting for dilutive items.

In millions except per share	1998	1997	1996
Earnings available for common shares	$ 132.2	$ 121.8	$ 103.7
Convertible bonds	.2	.3	.3
Earnings available for common shares after assumed conversion of dilutive securities	$ 132.4	$ 122.1	$ 104.0
EARNINGS PER SHARE:			
BASIC--			
Earnings before extraordinary item and cumulative effect of software accounting change	$ 1.65	$ 1.66	$ 1.46
Loss on retirement of debt	--	(.09)	--
Cumulative effect of software accounting change	--	(.06)	--
BASIC EARNINGS PER SHARE	$ 1.65	$ 1.51	$ 1.46
DILUTED			
Earnings before extraordinary item and cumulative effect of software accounting change	$ 1.63	$ 1.66	$ 1.46
Loss on retirement of debt	--	(.09)	--
Cumulative effect of software accounting change	--	(.06)	--
DILUTED EARNINGS PER SHARE	$ 1.63	$ 1.51	$ 1.46
Weighted average number of common shares used in basic earnings per share	80.07	80.42	70.81
Per share effect of dilutive securities:			
Stock options	.77	.18	--
Convertible bonds	.34	.40	.48
Weighted number of common shares and dilutive potential common stock used in diluted earnings per share	81.18	81.00	71.29

* ALL SHARE AND PER SHARE AMOUNTS HAVE BEEN RESTATED FOR THE 3-FOR-2 STOCK SPLIT.

CURRENCY ADJUSTMENTS

We translate the financial statements of our foreign subsidiaries and operations into U.S. dollars using the average monthly exchange rate during the period for income statement items. We use the year-end exchange rate for balance sheet items. When translating foreign currency-based assets and liabilities to U.S. dollars, we show any differences between accounts as translation adjustments in common shareowners' equity. For income statement accounts we show all changes in foreign currency relative to the U.S. dollar within the consolidated statements of income.

SOFTWARE COSTS

We capitalize the costs of internally-developed software that qualifies for capitalization under generally accepted accounting principles. We expense those costs that do not qualify. Typical capitalized costs include software coding and testing. Typical expensed costs include training and data conversion costs.

STOCK-BASED COMPENSATION

We issue stock options to employees from time to time and account for these options under Accounting Principles Board Opinion No. 25 (APB 25). All stock options issued are granted at the common stock's current market price. This means we record no compensation expense related to stock options. We also offer employees a 15% discount from the market price of our common stock.

Since we record options and discounts under APB 25, we must disclose the proforma compensation expense and earnings per share (dilutive method) as if we reflected the estimated fair value of options and discounts as compensation at the date of grant or issue. For the years ended December 31, 1998, 1997, and 1996, our proforma compensation expense would be $10.1 million, $4.9 million and $1.5 million, respectively. Our proforma earnings per share would have been reduced by $.07, $.03, and $.01 for the years ended December 31, 1998, 1997 and 1996, respectively.

NOTE 2:

A. TRADING ACTIVITIES:
PRICE RISK MANAGEMENT ACTIVITIES

We trade energy commodity contracts daily. Our trading activities attempt to match our portfolio of physical and financial contracts to current or anticipated market conditions. Within the trading portfolio, we take certain positions to hedge physical sale or purchase contracts and we take certain positions to take advantage of market trends and conditions. We record most energy contracts--both physical and financial--at fair market value. Changes in value are reflected in the consolidated statement of income. We use all forms of financial instruments including futures, forwards, swaps and options. Each type of financial instrument involves different risks. We believe financial instruments help us manage our exposure to changes in market prices and take advantage of selected arbitrage opportunities.

We refer to these transactions as price risk management activities.

MARKET RISK

The company's price risk management activities involve offering fixed price commitments into the future. The contractual amounts and terms of these financial instruments at December 31, 1998, are shown below:

<TABLE>
<CAPTION>

Dollars in millions	FIXED PRICE PAYOR	FIXED PRICE RECEIVER	MAXIMUM TERM IN YEARS
<S>	<C>	<C>	<C>
ENERGY COMMODITIES:			
Gas (trillion BTUs)	4,454.8	4,201.9	12
Electricity (megawatt-hours)	2,421,440	2,238,176	1
FINANCIAL PRODUCTS:			
Interest rate instruments	$2,507	$631	12

</TABLE>

Although we attempt to balance our physical and financial contracts in terms of quantities and contract performance, net open positions typically exist. We will at times create a net open position or allow a net open position to continue when we believe that future price movements will increase the portfolio's value. To the extent we have an open position, we are exposed to fluctuating market prices that may adversely impact our financial position or results from operations.

We measure the risk in our trading portfolio using value-at-risk methodologies, to simulate forward price curves in the energy markets and estimate the size of future potential losses. The quantification of market risk using value-at-risk methodologies provides a consistent measure of risk across diverse energy markets and products. The use of this method requires a number of key assumptions, such as:

- Selection of a confidence level (we use 95%).

- Estimated holding period (we use three days).

- Use of historical estimates of volatility and correlation with recent activity more heavily weighted.

At December 31, 1998, our value at risk was:

<TABLE>
<CAPTION>

In millions	(UNAUDITED)
<S>	<C>
Electricity	$.7
Natural gas	2.2

</TABLE>

We also use additional risk control mechanisms such as stress testing, daily loss limits and commodity position limits as well as daily monitoring of the trading activities by an independent function.

MARKET VALUATION

The market prices used to value price risk management activities reflect our best estimate of market prices considering various factors, including closing exchange and over-the-counter quotations, time value of money and price volatility factors underlying the commitments. We adjust market prices to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions.

We consider a number of risks and costs associated with the future contractual commitments included in our energy portfolio, including credit risks associated with the financial condition of counterparties, product

location (basis) differentials and other risks which our policy dictates. The value of all forward contracts is discounted to December 31, 1998 using an estimated rate. We continuously monitor the portfolio and value it daily based on present market conditions. The following table displays the market values of energy transactions at December 31, 1998 and 1997 and the average value for the year ended December 31, 1998 and 1997:

	Price Risk Management Assets		Price Risk Management Liabilities	
Dollars in millions	Average Value	December 31, 1998	Average Value	December 31, 1998
Independent power producers	$147.6	$165.4	$ --	$ --
Financial institutions	14.1	2.8	37.6	42.5
Oil and gas producers	31.4	38.4	24.9	34.1
Gas transmission	44.3	41.3	148.4	126.1
Energy marketers	116.5	90.4	83.6	46.6
Other	34.1	50.3	66.2	198.8
Gross value	388.0	388.6	360.7	448.1
Reserves	--	--	53.1	52.5
Total	$388.0	$388.6	$413.8	$500.6

	Price Risk Management Assets		Price Risk Management Liabilities	
Dollars in millions	Average Value	December 31, 1997	Average Value	December 31, 1997
Independent power producers	$158.7	$162.2	$ --	$ --
Financial institutions	16.1	15.4	28.7	36.6
Oil and gas producers	9.0	13.1	20.1	25.2
Gas transmission	14.6	31.7	44.2	144.4
Energy marketers	25.4	52.2	14.7	22.1
Other	5.6	8.4	3.8	5.5
Gross value	229.4	283.0	111.5	233.8
Reserves	--	--	57.9	60.4
Total	$229.4	$283.0	$169.4	$294.2

Future changes in the creditworthiness of our counterparties change the value of our portfolio. We adjust the value of contracts and set dollar limits with counterparties based on our assessment of their credit quality.

As of December 31, 1998, the future cash flow requirements, net of margin deposits, related to these financial instruments were $15.1 million. Margin deposits are required on certain financial instruments to address significant fluctuations in market prices.

The value of price risk management assets is concentrated into three contracts representing 36% of total asset value of the portfolio. This concentration of customers may impact the companys overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

B. NON-TRADING ACTIVITIES--HEDGING INSTRUMENTS

We enter into forwards, futures and other contracts related to our commodity businesses solely to hedge future production. The estimated fair value and cash flow requirements for these financial instruments are based on the market prices in effect at the financial statement date and do not necessarily reflect our entire trading portfolio.

NOTE 3:

ACCOUNTS RECEIVABLE

Our accounts receivable on the Consolidated Balance Sheets are comprised as follows:

In millions	December 31, 1998	December 31, 1997
Accounts receivable, net of allowance for bad debt	$1,302.6	$1,328.3
Unbilled revenue	82.9	116.8
Accounts receivable sale program	(248.0)	(280.0)
TOTAL	$1,137.5	$1,165.1

We sell, on a continuing basis, up to $280 million of eligible accounts receivable on a limited recourse basis. The financial institutions that buy our receivables charge a fee based on the dollar amount sold which is reflected as an expense in the consolidated statements of income. Our consolidated statements of income reflect fees associated with these sales of (in millions) $16.0 in 1998, $15.2 in 1997, and $12.2 in 1996.

NOTE 4:

PROPERTY, PLANT AND EQUIPMENT

The components of property, plant and equipment are as follows:

In millions	December 31, 1998	December 31, 1997
Electric utility	$2,527.4	$1,766.2
Gas utility	1,164.1	1,128.7
Gas gathering and pipeline systems	587.8	555.8
Other	425.8	261.8
Construction in process	57.0	88.2
	4,762.1	3,800.7
Less depreciation, depletion and amortization	1,448.2	1,320.4
PROPERTY, PLANT AND EQUIPMENT, NET	$3,313.9	$2,480.3

Our property, plant and equipment includes acquisition-related intangibles that are being amortized over useful lives not exceeding 40 years.

CUMULATIVE EFFECT OF SOFTWARE ACCOUNTING CHANGE

In 1997, we changed our method of accounting for internally developed software costs to conform with the new requirements of an accounting standard that became effective November 20, 1997. This accounting change reduced 1997 net income by $4.8 million and is shown in our consolidated statement of income as a cumulative effect of software accounting change.

NOTE 5:

ASSET IMPAIRMENTS

We have adjusted the reported value of certain assets over the last three years. Although it was a requirement that assets reflect realizable values, it was not until the passage of Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" (SFAS 121), that impairment provisions were determined on a consistent basis and methodology. The table below summarizes the impairment provisions we have recorded since 1996 and the related reasons.

<TABLE>
<CAPTION>

In millions	For the years ended December 31, 1998	1997	1996
<S>	<C>	<C>	<C>
Retail marketing assets (a)	$13.2	$ --	$ --
Investment in EnergyOne, L.L.C. (b)	8.0	--	--
Investment in a power project (c)	6.5	--	--
Royalty interest (d)	--	15.5	--
Technology-related investment (e)	--	11.0	--
TOTAL	$27.7	$26.5	--

</TABLE>

(a) In June 1998, we revised our strategic plan to curtail our retail activities. This revised strategy diminished the value of certain retail assets and required an impairment provision to be recorded.
(b) In April 1998, we agreed with our partner to dissolve our partnership due to unfavorable market conditions and unsatisfactory execution of its strategy. As a result of this decision, the recorded value of EnergyOne, L.L.C. became overstated related to liquidation values and an impairment provision was recorded.
(c) In June 1998, we concluded that the cash flows from a power project would not be sufficient to recover its recorded value. This project was exploring certain methods to enhance cash flows, such as fuel mix changes, but based on our analysis, we concluded that no viable alternatives existed to improve operations. We recorded an impairment based on this analysis.
(d) In 1997, we reduced the carrying value of royalty interests that are tied to the drilling success of some properties we sold in 1995. Based on information from the company we sold the properties to, we concluded that an impairment charge was necessary.
(e) In 1997, we wrote off our investment in a technology joint venture organized to develop energy related innovations. When no marketable products were developed we reassessed the value of this investment and determined that future cash flows, if any, would not recover invested costs.

NOTE 6:

INVESTMENTS IN SUBSIDIARIES AND PARTNERSHIPS

Our consolidated balance sheet contains various equity investments as shown in the table below. Our New Zealand investment is now fully consolidated within the 1998 balance sheet but before 1998, our New Zealand operations were equity investments. The table below summarizes our investments and related equity earnings.

<TABLE>
<CAPTION>

Dollars in millions	Ownership at 12/31/98	Country	Investment at December 31, 1998	1997	Equity Earnings Year Ended December 31, 1998	1997	1996
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
UAHL investment	34.0%	Australia	$221.9	$237.9	$69.1	$28.6	$42.7
UNZ investment (a)							
WEL Energy Group Ltd. (WEL)	--	New Zealand	--	39.6	11.3	4.5	6.2
Power New Zealand (PNZ)	--	New Zealand	--	115.2	8.1	9.2	11.2
UtilCo Group partnerships (b)	17%--50%	U.S. & Jamaica	193.7	199.7	33.4	29.6	48.5
Oasis Pipe Line Company (Oasis) (c)	35%	United States	97.1	96.3	1.1	.9	.1
Other			7.1	2.5	2.1	(4.0)	--

TOTAL	$519.8	$691.2	$125.1	$68.8	$108.7

(a) We acquired a controlling interest in 1998 and as a result our New Zealand investments are reflected on a consolidated basis.
(b) We own interests in 17 independent power projects located in seven states and Jamaica. Of these, 16 are currently in commercial operation. These investments are aggregated because individual investments are not significant.
(c) In 1996, our Aquila Gas Pipeline (AQP) subsidiary acquired an equity interest in a pipeline for $132.0 million. In 1997, AQP sold 5% of its interest to another partner.

The summarized combined financial information of unconsolidated material equity investments is presented below:

In millions	December 31, 1998 (a)	1997
ASSETS:		
Current assets	$ 322.7	$ 338.1
Non-current assets	2,084.8	2,840.6
TOTAL ASSETS	$2,407.5	$3,178.7
LIABILITIES AND EQUITY		
Current liabilities	$ 335.9	$ 449.8
Non-current liabilities	1,344.2	1,718.1
Equity	727.4	1,010.8
TOTAL LIABILITIES AND EQUITY	$2,407.5	$3,178.7

In millions	Year Ended December 31, 1998 (a)	1997	1996
OPERATING RESULTS:			
Revenues	$850.3	$1,294.7	$1,277.8
Costs and expenses	752.4	1,140.7	1,109.1
NET INCOME	$97.9	$ 154.0	$ 168.7

(a) Excludes UnitedNetworks since this subsidiary is reflected in the consolidated statements.

NOTE 7:

NEW ZEALAND AND AUSTRALIA TRANSACTIONS

INTEREST IN NEW ZEALAND ELECTRIC UTILITIES

Through a series of transactions in 1998, we acquired an additional 48% of Power New Zealand's common stock for approximately $245 million, increasing our ownership to 78.6%. Concurrent with this acquisition, we sold our 39.6% interest in New Zealand's WEL Energy Group, which we acquired throughout 1995, 1996 and 1997, and bought out the 21% minority shareholder in our New Zealand subsidiary, UtiliCorp N.Z., Inc.

New Zealand's Electricity Industry Reform Act of 1998 requires all the country's utilities to separate ownership of their lines (network) and supply (generation and retail) businesses. Power New Zealand, with approximately 90% of its assets and earnings in the lines area, on November 13 announced its intention to remain in the network business and to exit the supply business. It also agreed to purchase the Wellington-based lines assets of TransAlta New Zealand Ltd. and to sell to TransAlta its retail electricity business serving the Auckland area for a net expenditure by Power New Zealand of $238 million.

Because Power New Zealand's name transferred to TransAlta as part of the retail business TransAlta acquired, the network business became UnitedNetworks Limited on January 1, 1999.

On November 20, Power New Zealand agreed to purchase the electric line assets of neighboring power company TrustPower Limited for approximately $261 million. The assets became part of a greater network which includes parts of metropolitan Auckland and other areas in the central and southern regions of New Zealand's North Island. The TrustPower transaction closed in January 1999. Completion of the TransAlta and TrustPower transactions created the country's largest electricity distribution network, serving about 468,000 customers.

INITIAL PUBLIC OFFERING--UNITED ENERGY LIMITED

In May 1998, United Energy Limited (UEL) sold 42% of its common stock to the Australian public and as a result, we recorded a $45.3 million gain. The partial sale to the public reduced our effective ownership percentage to 29%. Concurrent with UEL's stock offering, we bought an additional 5% in UEL from another company to bring our ownership in UEL to 34%. Prior to the common stock sale, UEL repaid approximately $101 million in debt notes owed to us. The management agreement between UEL and UtiliCorp remains in place.

NOTE 8: REGULATORY ASSETS

Our domestic utility operations are regulated by state or local authorities. Our financial statements therefore include the economic effects of rate regulation. This means our consolidated balance sheet shows some assets and liabilities that would not be found on the balance sheet of a non-regulated company. There is a risk that if the domestic utility industry deregulates, we may have to remove the effects of regulation from our financial statements.

The following table lists the regulatory assets and liabilities recorded at December 31, 1998 and 1997. These are primarily shown as deferred charges and credits on the consolidated balance sheets.

<TABLE>
<CAPTION>

In millions	1998	1997
<S>	<C>	<C>
Income taxes	$ 59.0	$ 55.2
Environmental liabilities	11.5	11.2
Debt-related costs	17.8	19.6
Regulatory accounting orders	6.4	8.4
Demand-side management programs	10.3	13.0
Other	9.2	15.3
TOTAL REGULATORY ASSETS	$ 114.2	$ 122.7
Regulatory Liabilities	17.7	16.8
NET REGULATORY ASSETS	$ 96.5	$ 105.9

</TABLE>

NOTE 9: SHORT-TERM DEBT

Short-term debt includes the following components:

<TABLE>
<CAPTION>

	December 31,	
Dollars in millions	1998	1997
<S>	<C>	<C>
Bank borrowing and other	$ 235.6	$ 113.8
Commercial paper	--	--
TOTAL	$ 235.6	$ 113.8
Weighted average interest rate at year end	4.31%	6.21%

</TABLE>

We have a $150 million commercial paper program supported by a $250 million revolving credit agreement. The credit agreement allows us to issue commercial paper at a favorable interest rate. Our credit agreement contains restrictive covenants and charges an annual commitment fee of .17% on the unused portion.

During 1998 we put in place two New Zealand credit facilities that we used to acquire additional shares in UnitedNetworks. These facilities have the following terms.

Dollars in millions

Maximum Amount	Amount Outstanding	Interest Rate	Maturity Date
$NZ 425	$NZ 403.9	4.30%	October 1999
$NZ 45	$NZ 42.4	4.47%	June 1999

The outstanding balances from these credit facilities comprise the total short-term debt balance at December 31, 1998. The interest rates may vary with changes in the New Zealand bank bill rate and carry a commitment fee of.20% on unused amounts.

NOTE 10: LONG-TERM DEBT

This table summarizes the company's long-term debt:

In millions	December 31, 1998	1997
FIRST MORTGAGE BONDS:		
Various, 9.94%*, due 1999-2008	$ 19.5	$ 20.6
SENIOR NOTES:		
6.0% Series, retired April 1, 1998	--	70.0
9.21% Series, due October 11, 1999	50.0	50.0
8.45% Series, due November 15, 1999	100.0	100.0
Aquila Southwest Energy 8.29% Series, due September 15, 2002	50.0	62.5
6.875% Series, due October 1, 2004	150.0	150.0
6.375% Series, due June 1, 2005	100.0	100.0
6.70% Series, due October 15, 2006	100.0	100.0
8.2% Series, due January 15, 2007	130.0	130.0
10.5% Series, due December 1, 2020	55.9	55.9
9.0% Series, due November 15, 2021	150.0	150.0
8.0% Series, due March 1, 2023	125.0	125.0
SECURED DEBENTURES OF WEST KOOTENAY POWER:		
9.15%*, due 2001-2023	66.2	71.3
CONVERTIBLE SUBORDINATED DEBENTURES:		
6.625%, due July 1, 2011 (convertible into 337,500 common shares)	5.3	5.8
New Zealand Denominated Credit Facilities, due June 30, 1999 and January 15, 2002	379.2	64.7
Australian Denominated Credit Facility, due July 20, 2000	101.0	195.1
Other notes and obligations	42.5	57.3
TOTAL LONG-TERM DEBT	1,624.6	1,508.2
Less current maturities	248.8	149.6
LONG-TERM DEBT, NET	$ 1,375.8	$ 1,358.6
Fair value of long-term debt, including current maturities (a)	$ 1,752.8	$ 1,581.1

* WEIGHTED AVERAGE INTEREST RATE.

(a) THE FAIR VALUE OF LONG-TERM DEBT IS BASED ON CURRENT RATES AT WHICH THE COMPANY COULD BORROW FUNDS WITH SIMILAR REMAINING MATURITIES.

Substantially all of our domestic utility plant is subject to the lien of various mortgage indentures. We cannot issue additional mortgage bonds under these indentures without directly securing certain Senior Notes equally as any mortgage bond issue. Currently we have no plans to issue mortgage bonds.

The amounts of long-term debt maturing in each of the next five years and thereafter are shown at right:

In millions	Maturing Amounts
1999	$ 248.8
2000	164.5
2001	44.4
2002	243.0
2003	10.4
Thereafter	913.5
TOTAL	$ 1,624.6

RETIREMENT OF DEBT

In March 1997 we retired, at a premium, $69.1 million of our 10.5% series senior notes that were to mature in 2020. This transaction resulted in an extraordinary loss of $7.2 million, net of an income tax benefit of $4.5 million.

NEW ZEALAND DENOMINATED CREDIT FACILITIES

UtiliCorp South Pacific, Inc. (USP) has a $NZ135 million credit facility with a consortium of banks that was used to finance a portion of the investments made by UNZ. The interest rate fluctuates (4.36% at December 31, 1998) with changes in the New Zealand bank bill rate. The credit facility matures on June 30, 1999. A commitment fee of .20% applies to the unused portion of the credit facility. UnitedNetworks has a three-year term loan facility to finance the acquisitions of TransAlta's (December 1998) and TrustPower's (January 1999) lines businesses. The maximum amount of the facility is $NZ 1 billion. The interest rate is fixed through series of swaps at 7.70%

AUSTRALIAN DENOMINATED CREDIT FACILITIES

We maintain a $A150 million credit facility with a bank that matures in July 2000. The interest rate for $A100 million of this facility fluctuates with changes in the Australian bank bill rate. At December 31, 1998, $A100 million was outstanding under the floating rate portion of this facility at a rate of 5.21%. The interest rate on the remaining $A50 million of this facility is fixed at 7.48%, with $A50 million outstanding at December 31, 1998. A commitment fee of .20% applies to the unused portion of the credit facility.

We also have a $A100 million credit facility with a consortium of banks that matures in July 2000. The interest rate on this facility fluctuates with changes in the Australian bank bill rate. At December 31, 1998, $A15 million was outstanding at a rate of 5.33%. A commitment fee of .20% applies to the unused portion of the credit facility.

NOTE 11: COMPANY-OBLIGATED PREFERRED SECURITIES

In June 1995, UtiliCorp Capital L.P. (UC), a limited partnership of which we are the general partner, issued 4 million shares of 8.875% Cumulative Monthly Income Preferred Securities, Series A, for $100 million. The limited partnership interests represented by the preferred securities are redeemable at the option of UC, after June 12, 2000, at $25 per preferred security plus accrued interest and unpaid dividends.

Holders of the securities are entitled to receive dividends at an annual rate of 8.875% of the liquidation preference value of $25. Dividends are payable monthly and in substance are tax-deductible by the company. The securities are shown as company-obligated mandatorily redeemable preferred securities of partnership on the consolidated balance sheets. The dividends are shown as minority interest in income of partnership in the consolidated statements of income.

NOTE 12: CAPITAL STOCK

COMMON STOCK OFFERING

We have two types of authorized common stock--unclassified common stock and Class A common stock. No Class A common stock is issued or outstanding. As of December 31, 1998, we had no restrictions on our ability to pay cash dividends.

COMMON STOCK SPLIT

In November 1998, our Board of Directors approved a 3-for-2 common stock split. The stock split is effective March 12, 1999 and all share amounts, share prices and per share figures have been restated.

STOCKHOLDER RIGHTS PLAN

Our Board adopted a rights plan and declared a dividend distribution of one right for each outstanding common share. The rights are not currently exercisable. Each right, when exercisable, would entitle each right holder to purchase one one-thousandth of a share of Series A Participating cumulative Preference Stock at a price of $77. The rights become exercisable if a person has acquired 15% of the outstanding common stock. Once the rights become exercisable, each rights holder can purchase common stock in the company at a market value twice the exercise price of the right.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

We offer to current and potential shareholders a Dividend Reinvestment and Common Stock Purchase Plan (the Stock Plan).

The Stock Plan allows participants to purchase up to $10,000 per month of common stock at a five-day average market price, without sales commissions. The Stock Plan also allows members to reinvest dividends into additional common shares at a 5% discount.

For the year ended December 31, 1998, 1,125,000 shares were issued under the Stock Plan. As of December 31, 1998, 6,206,537 shares were available to issue under this plan.

EMPLOYEE STOCK PURCHASE PLAN

Participants in our Employee Stock Purchase Plan have the opportunity to buy shares of common stock at a reduced price through regular payroll deductions and/or lump sum deposits of up to 20% of the employee's base salary. Contributions are credited to the participant's account throughout an option period. At the end of the option period, the participant's total account balance is applied to the purchase of common stock. The shares are purchased at 85% of the lower of the market price

on the first day or the last day of the option period. Participants must be enrolled in the Plan as of the first day of an option period in order to participate in that option period.

RESTATED SAVINGS PLAN

A defined contribution plan, the Restated Savings Plan (Savings Plan), covers all of our full-time and eligible part-time employees. Participants may generally elect to contribute up to 15% of their annual pay on a before- or after-tax basis subject to certain limitations. The company generally matches contributions up to 6%. Participants may direct their contributions into five different investment options. All company matching contributions are in UtiliCorp common stock. The Savings Plan also includes a stock contribution fund to which the company can contribute an additional amount of company common stock for participants.

STOCK INCENTIVE PLAN

Our Stock Incentive Plan enables the company to grant common shares to certain employees as restricted stock awards and as stock options. Shares issued as restricted stock awards are held by the company until certain restrictions lapse, generally on the third award anniversary. The market value of the stock, when awarded, is amortized to compensation expense over the three-year period. Stock options granted under the Plan allow the purchase of common shares at a price not less than fair market value at the date of grant. Options are generally exercisable commencing with the first anniversary of the grant. They grant 10 years after the date of grant.

EMPLOYEE STOCK OPTION PLAN

The Board approved the establishment of an Employee Stock Option Plan in 1991. This Plan provides for the granting of up to 1.5 million stock options to full-time employees other than those eligible to receive options under the Stock Incentive Plan. Stock options granted under the Employee

Stock Option Plan carry the same provisions as those issued under the Stock Incentive Plan. During 1988 and 1992, respectively, options for 1,278,713 and 1,114,350 shares were granted to employees. The exercise prices of these options are $24.02 and $18.21, respectively.

This table summarizes stock options as of December 31, 1998 and 1997:

Shares	1998	1997
BEGINNING BALANCE	3,764,441	3,300,675
Granted	2,706,526	1,684,530
Exercised	(803,565)	(922,935)
Cancelled	(226,999)	(297,829)
ENDING BALANCE	5,440,403	3,764,441
WEIGHTED AVERAGE PRICES:		
Beginning balance	$ 18.65	$ 18.63
Granted price	23.94	18.53
Exercised price	18.79	18.40
Cancelled price	20.47	18.47
Ending balance	21.15	18.65

At December 31, 1998, total exercisable restricted stock awards and stock options were 670,908 shares (at prices ranging between $14.59 and $25.00).

NOTE 13: INCOME TAXES

Income tax expense consists of the following components:

	Year Ended December 31,		
In millions	1998	1997	1996
CURRENTLY PAYABLE:			
Federal	$ 33.9	$ 27.1	$ 35.0
Foreign	1.7	7.1	14.2
State	6.5	6.5	5.5
DEFERRED:			
Federal	41.5	42.1	23.0
State	4.2	8.2	4.3
Investment tax credit amortization	(1.2)	(1.3)	(1.3)
TOTAL INCOME TAX EXPENSE	$ 86.6	$ 89.7	$ 80.7

The principal components of deferred income taxes consist of the following:

	December 31,	
In millions	1998	1997
DEFERRED TAX ASSETS:		
Alternative maximum carryforward	$ 93.4	$ 98.3
DEFERRED TAX LIABILITIES AND CREDITS:		
Accelerated depreciation and other plant differences:		

Regulated	180.5	167.5
Non-regulated	186.7	168.9
Regulatory asset--SFAS 109	42.4	38.6
Mark-to-market reserve	50.4	25.8
Other, net	62.9	60.2
TOTAL DEFERRED TAX LIABILITIES AND CREDITS	522.9	461.0
DEFERRED INCOME TAXES AND CREDITS, NET	$ 429.5	$ 362.7

</TABLE>

Our effective income tax rates differed from the statutory federal income tax rates primarily due to the following:

<TABLE>
<CAPTION>

	December 31,		
Percent	1998	1997	1996
<S>	<C>	<C>	<C>
Statutory Federal Income Tax Rate	35.0%	35.0%	35.0%
TAX EFFECT OF:			
Temporary difference passed through, primarily removal costs	--	--	.2
Investment tax credit amortization	(.5)	(.6)	(.7)
State income taxes, net of federal benefit	4.9	5.8	5.8
Difference in tax rate of foreign subsidiaries	(3.1)	(1.9)	(.7)
Other	3.3	1.8	3.7
EFFECTIVE INCOME TAX RATE	39.6%	40.1%	43.3%

</TABLE>

We had alternative minimum tax credit carryforwards of approximately $93.4 million at December 31, 1998. Alternative minimum tax credits can be carried forward indefinitely. The company has not recorded a valuation allowance against its tax credit carryforwards.

We have made no provision for U.S. income taxes on undistributed earnings from our international businesses ($145.0 million at December 31, 1998) because it is our intention to reinvest those earnings. If we distribute those earnings in the form of dividends, we may be subject to both foreign withholding taxes and U.S. income taxes net of allowable foreign tax credits. Consolidated income before income taxes for the years ended December 31, 1998, 1997 and 1996 included (in millions) $70.5, $13.6 AND $39.2, respectively, from international operations.

NOTE 14: EMPLOYEE BENEFITS

PENSIONS

The following table shows the funded status of our pension plans and the amounts included in the consolidated balance sheets and statements of income.

<TABLE>
<CAPTION>

	Pension Benefits			Other Benefits		
Dollars in millions	1998	1997	1996	1998	1997	1996
<S>	<C>	<C>	<C>	<C>	<C>	<C>
CHANGE IN BENEFIT OBLIGATION:						
Benefit obligation at start of year	$ 205.4	$ 185.9	$ 183.9	$ 42.6	$ 39.0	$ 40.2
Service cost	7.7	6.2	6.5	.7	.7	1.0
Interest cost	14.4	13.8	13.0	2.7	2.8	2.9
Plan participants' contribution	.6	.7	.7	.8	.8	.8
Amendments	8.9	.5	.4	.3	(.1)	--
Actuarial (gain) loss	(1.2)	8.3	(7.1)	1.6	.6	(3.4)
Benefits paid	(12.1)	(8.5)	(11.8)	(6.3)	(1.1)	(2.5)
Foreign Currency Exchange changes	(2.4)	(1.5)	.3	(.2)	(.1)	--

Benefit obligation at end of year	$ 221.3	$ 205.4	$ 185.9	$ 42.2	$ 42.6	$ 39.0
CHANGE IN PLAN ASSETS:						
Fair value of plan assets at start of year	$ 240.1	$ 208.7	$ 191.7	$ 4.8	$ .5	$ .9
Actual return on plan assets	(.5)	38.8	26.0	.3	.1	--
Employer contribution	1.6	1.8	1.8	7.8	4.5	1.4
Plan participants' obligation	.6	.7	.7	.8	.8	.8
Benefits paid	(12.1)	(8.5)	(11.7)	(6.3)	(1.1)	(2.6)
Foreign Currency Exchange changes	(2.1)	(1.4)	.2	--	--	--
Fair value of plan assets at end of year	$ 227.6	$ 240.1	$ 208.7	$ 7.4	$ 4.8	$ .5
Funded status	$ 6.3	$ 34.7	$ 22.8	$(34.8)	$ (37.8)	$ (38.5)
Unrecognized transition amount	(8.9)	(10.1)	(11.3)	28.3	30.4	32.4
Unrecognized net actuarial (gain) loss	19.4	(2.4)	8.2	(8.8)	(7.7)	(8.5)
Unrecognized prior service cost	9.8	1.1	.9	.3	--	--
Prepaid (accrued) benefit cost	$ 26.6	$ 23.3	$ 20.6	$(15.0)	$ (15.1)	$ (14.6)
WEIGHTED AVERAGE ASSUMPTIONS AS OF SEPTEMBER 30:						
Discount rate	6.75%	7.17%	7.60%	6.75%	7.00%	7.50%
Expected return on plan assets	9.73%	9.73%	8.0-10.0%	7.00%	10.00%	8.25%
Rate of compensation increase	5.09%	5.36%	5.0-5.4%	5.40%	5.40%	5.0-5.4%

</TABLE>

For measurement purposes, we assumed a 6.00% annual rate of increase in the per capita cost of covered health benefits for each future fiscal year.

<TABLE>
<CAPTION>

	Pension Benefits			Other Benefits		
Dollars in millions	1998	1997	1996	1998	1997	1996
COMPONENTS OF NET PERIODIC BENEFIT COST						
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Service cost	$ 7.7	$ 6.2	$ 6.5	$ .7	$ .7	$ 1.0
Interest cost	14.4	13.8	13.0	2.7	2.8	2.9
Expected return on plan assets	(22.8)	(19.8)	(18.3)	(.3)	(.2)	--
Amortization of transition amount	(1.2)	(1.2)	(1.2)	2.0	2.0	2.0
Amortization of prior service cost	--	--	(.1)	--	--	--
Recognized net actuarial (gain) loss	--	--	.4	(.2)	(.3)	--
Regulatory adjustment	.8	.8	.9	--	--	--
NET PERIODIC BENEFIT COST	$ (1.1)	$ (.2)	$ 1.2	$ 4.9	$ 5.0	$ 5.9

</TABLE>

The U.S. pension plan was amended effective October 1, 1998 to provide the same pension benefits for almost all participants. In one location, we recorded pension expense using a modified amortization of gains and losses consistent with the rate treatment allowed for this cost.

Our health care plans are contributory, with participants' contributions adjusted annually. The life insurance plans are non-contributory. We have assumed in estimating future health care costs future cost-sharing changes. The expense recognition for health care costs does not necessarily match the cost estimates due to certain differences in regulatory accounting at domestic utility operations.

The assumed health care cost trends significantly affect the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for Fiscal Year 1998.

<TABLE>
<CAPTION>

	1 Percentage-Point	
In millions	Increase	Decrease
<S>	<C>	<C>

Effect on total of service and interest cost components	$ .4	$ (.3)
Effect on post-retirement benefit obligation	3.5	(2.9)

</TABLE>

In addition to the defined benefit retirement plans and health care plans, we contribute to a defined contribution savings plan. Company contributions were $8.4 million and $8.1 million during the plan years ending December 1998 and 1997, respectively.

NOTE 15: COMMITMENTS AND CONTINGENCIES

Commitments

We have various commitments for the next five years relating to power and gas supply commitments, fixed price sales obligations, and lease and rental commitments. A summary is below. As with any estimates, the actual amounts paid or received could differ materially.

<TABLE>
<CAPTION>

Dollars in millions except per unit	1999	2000	2001	2002	2003
<S>	<C>	<C>	<C>	<C>	<C>
Capital expenditures	$ 230.0	$ 316.0	$ 326.0	$ 185.0	$ 189.0
Future minimum lease payments	$ 23.6	$ 30.9	$ 35.9	$ 34.7	$ 33.8
Purchased power obligations	$ 63.0	$ 60.0	$ 37.6	$ 23.7	$ 23.6
Purchased power obligations (GIGAWATTS)	1,149	989	827	308	308
Cash flow obligation on prepaid gas sales	$ 29.6	$ 32.9	$ 34.2	$ 35.8	$ 40.9
Coal contracts	$ 43.8	$ 44.0	$ 31.1	$ 30.0	$ 30.9
Price ranges	$12.85 to $23.75 per ton				
Fixed price sales physical obligations (TRILLION BTUs)	637.7	101.8	40.9	34.0	36.0
Price ranges	$1.24 to $4.10 per MCF				
Fixed price purchase physical obligations (TRILLION BTUs)	590.1	49.6	19.2	3.2	--
Price ranges	$1.23 to $3.30 per MCF				
Fixed price sales obligations (GIGAWATTS)	33,166	655	--	--	--
Price ranges	$11.00 to $128.00 per MWH				
Fixed price purchase obligations (GIGAWATTS)	33,749	534	--	--	--
Price ranges	$12.00 to $123.00 per MWH				

</TABLE>

Future minimum lease payments primarily relate to our interest in the Jeffrey Energy Center, peaking turbines, coal cars and office space. Rent expense for the years 1998, 1997 and 1996 was (in millions) $31.1, $32.1 and $29.4, respectively.

A 1998 court ruling required United Gas to pay the gas cost amount in accordance with a contract that was subject to a legal dispute. In addition, United Gas is required to pay interest to the supplier on the $38 million. We estimate this will cost $6.8 million.

In 1998 we entered into a 15-year agreement to obtain the rights to dispatch 267 megawatts of power from facilities currently being built by a third party. As part of the agreement we will provide the natural gas to the power plant and will be able to dispatch the power. The plant is expected to be available in June 2000.

ENVIRONMENTAL

We are subject to various environmental laws. These include regulations governing air and water quality and the storage and disposal of hazardous or toxic wastes. We continually assess ways to ensure we comply with laws and regulations on hazardous materials and hazardous waste and remediation activities.

We own or previously operated 29 former manufactured gas plants (MGPs) which may, or may not, require some form of environmental remediation. We have contacted appropriate federal and state agencies and are working to determine what, if any, specific cleanup activities these sites may require.

As of December 31, 1998, we estimate cleanup costs on our identified MGP sites to be $10.0 million. This estimate could change materially when we have investigated further. It could also be affected by the actions of environmental agencies and the financial viability of other responsible parties. Ultimate liability also may be affected significantly if we are held responsible for parties unable to contribute financially to the cleanup effort.

We have received favorable rate orders that enable us to recover environmental cleanup costs in certain jurisdictions. In other jurisdictions, there are favorable regulatory precedents for recovery of these costs. We are also pursuing recovery from insurance carriers and other potentially responsible parties.

In December 1996, the U.S. Environmental Protection Agency (EPA) published its final rule for nitrous oxide (NOx) emissions as required by the Clean Air Act Amendments of 1990. The new NOx regulations require that we install additional emissions control equipment at one of our power plants by January 1, 2000.

In October 1998, the EPA published new air quality standards to further reduce the emission of NOx. These more strict standards will require us to install new equipment on our baseload coal units in Missouri that we estimate will cost $35 million. The ultimate cost is under debate and subject to change. The new standards as written are effective in May 2003.

We do not expect final resolution of these environmental matters to have a a material adverse affect on our financial position or results of operations.

RATE PROCEEDING

We filed and have pending a request to increase our gas and electric rates in West Virginia by $4.7 million and $2.9 million, respectively. We expect final rates in late 1999.

OTHER

The company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. We do not expect the amount of liability, if any, from these actions to materially affect our consolidated financial position or results of operations.

NOTE 16: SEGMENT INFORMATION

A. BUSINESS LINES

<TABLE>
<CAPTION>

	Year Ended December 31,			
Dollars in millions	1998		1997	1996
<S>	<C>	<C>	<C>	<C>
SALES:				
Regulated Businesses--				
Electric	$ 616.6	4.9%	$ 557.4	$ 519.3
Gas	622.5	5.0	767.4	727.9
Other	233.7	1.8	258.7	124.8
Total Regulated Businesses	1,472.8	11.7	1,583.5	1,372.0
Aquila Energy	10,585.6	84.3	7,031.0	2,672.7
International and other	505.0	4.0	311.8	287.6
TOTAL	$ 12,563.4	100.0%	$ 8,926.3	$ 4,332.3

</TABLE>

<TABLE>

	Year Ended December 31,			
Dollars in millions	1998		1997	1996
<S>	<C>	<C>	<C>	<C>
EARNINGS BEFORE INTEREST AND TAXES:				
Regulated Businesses	$ 207.7	59.1%	$ 197.5	$ 206.3
Aquila Energy (a)	54.1	15.4	82.4	90.2

International (b)	103.8	29.5	52.5	79.7
Corporate and other	(14.2)	(4.0)	26.7	(50.0)
TOTAL	$ 351.4	100.0%	$ 359.1	$ 326.2

</TABLE>

(a) THE AQUILA ENERGY SEGMENT INCLUDES EQUITY EARNINGS OF $34.5, $30.5 AND $48.6 MILLION IN 1998, 1997 AND 1996, RESPECTIVELY.

(b) THE INTERNATIONAL SEGMENT INCLUDES OPERATING ACTIVITIES IN AUSTRALIA, NEW ZEALAND, CANADA AND THE UNITED KINGDOM WHICH HAD TOTAL EQUITY EARNINGS OF $88.5, $42.3 AND $60.1 MILLION IN 1998, 1997 AND 1996, RESPECTIVELY.

<TABLE>

	Year Ended December 31,			
Dollars in millions	1998		1997	1996
<S>	<C>	<C>	<C>	<C>
DEPRECIATION, DEPLETION AND AMORTIZATION:				
Regulated Businesses	$ 109.1	72.7%	$ 84.9	$ 83.2
Aquila Energy	27.7	18.5	27.6	28.6
International	13.0	8.7	11.0	12.5
Corporate and other	.2	.1	6.1	1.1
TOTAL	$ 150.0	100.0%	$ 129.6	$ 125.4

</TABLE>

<TABLE>
<CAPTION>

	December 31,		
Dollars in millions	1998		1997
<S>	<C>	<C>	<C>
IDENTIFIABLE ASSETS:			
Regulated Businesses	$ 2,040.9	34.1%	$ 2,101.9
Aquila Energy	2,290.9	38.2	2,275.5
International	1,437.0	24.0	789.0
Corporate and other	222.7	3.7	(52.9)
TOTAL	$ 5,991.5	100.0%	$ 5,113.5

</TABLE>

<TABLE>
<CAPTION>

	Year Ended December 31,			
Dollars in millions	1998		1997	1996
<S>	<C>	<C>	<C>	<C>
CAPITAL EXPENDITURES:				
Regulated Businesses--				
Electric	$ 55.3	27.1%	$ 57.4	$ 64.3
Gas	46.5	22.8	59.2	48.5
Total Regulated Businesses	101.8	49.9	116.6	112.8
Aquila Energy	33.8	16.5	28.4	26.4
International	20.0	9.8	19.4	21.5
Corporate and other	48.7	23.8	38.2	70.5
TOTAL	$ 204.3	100.0%	$ 202.6	$ 231.2

</TABLE>

B. GEOGRAPHICAL INFORMATION

<TABLE>
<CAPTION>

Dollars in millions	Year Ended December 31, 1998		1997	1996
<S>	<C>	<C>	<C>	<C>
SALES:				
United States	$ 10,924.8	87.0%	$ 8,007.8	$ 3,962.5
Canada (a)	1,222.4	9.7	704.4	180.9
United Kingdom	359.6	2.9	214.1	188.9
New Zealand	56.6	.4	--	--
TOTAL	$ 12,563.4	100.0%	$ 8,926.3	$ 4,332.3
Earnings Available for Common Shares:				
United States	$ 84.2	63.7%	$ 105.2	$ 77.0
Canada (a)	6.7	5.1	10.8	9.5
Australia (b)	40.3	30.5	11.3	14.1
New Zealand	6.5	4.9	1.9	2.4
United Kingdom	(5.5)	(4.2)	(7.4)	.7
TOTAL	$ 132.2	100.0%	$ 121.8	$ 103.7

</TABLE>

<TABLE>
<CAPTION>

Dollars in millions	December 31, 1998		1997
<S>	<C>	<C>	<C>
IDENTIFIABLE ASSETS:			
United States	$ 4,336.5	72.4%	$ 4,205.6
Canada (a)	439.9	7.3	376.4
Australia (b)	230.9	3.9	270.3
New Zealand	839.4	14.0	160.7
United Kingdom	144.8	2.4	100.5
TOTAL	$ 5,991.5	100.0%	$ 5,113.5

</TABLE>

(a) CANADIAN SALES, EARNINGS AVAILABLE FOR COMMON SHARES AND IDENTIFIABLE ASSETS INCLUDE AQUILA ENERGY'S CANADIAN OPERATIONS AND VARIOUS SMALL CANADIAN GAS MARKETING COMPANIES.

(b) EARNINGS AVAILABLE AND A MAJORITY OF THE IDENTIFIABLE ASSETS RELATE TO EQUITY INVESTMENTS.

NOTE 17: MERGERS

ST. JOSEPH LIGHT & POWER COMPANY
(UNAUDITED)

On March 4, 1999, we agreed to merge with St. Joseph Light & Power Company (SJL&P). Under the agreement, SJL&P shareholders will receive a fixed $23.00 per share for each SJL&P common share. This will be converted into UtiliCorp common shares when the merger is completed. We expect to account for the transaction as a pooling of interests, although that is not a condition of the agreement. The merger is subject to approval by SJL&P shareholders and state and federal regulatory agencies and is expected to close in mid-2000.

KANSAS CITY POWER & LIGHT COMPANY (KCPL)

In September 1996, KCPL terminated the Amended and Restated Agreement and Plan of Merger (the Agreement) among KCPL, KC Merger Sub, Inc., UtiliCorp United Inc. and KC United Corp., which would have provided for the merger of UtiliCorp and KCPL.

Since KCPL's shareholders did not approve the merger under the terms of the Agreement, KCPL was required to pay us $5.0 million. We received this payment in September 1996. In connection with the Agreement termination, we expensed deferred merger costs of about $11.0 million (pretax), net of the termination fee payment.

In February 1997, Western Resources Inc. and KCPL signed a definitive agreement to merge. As a result, KCPL paid us a $53.0 million breakup fee. We recorded this merger termination fee in the first quarter of 1997.

NOTE 18:
QUARTERLY FINANCIAL DATA (Unaudited)

Financial results for interim periods do not necessarily indicate trends for any 12-month period. Quarterly results can be affected by the timing of acquisitions, the effect of weather on sales, and other factors typical of utility operations and energy related businesses.

	1998 QUARTERS (a)				1997 QUARTERS (a)			
IN MILLIONS, EXCEPT PER SHARE	FIRST	SECOND	THIRD	FOURTH	First	Second	Third	Fourth
Sales	$ 2,895.9	$ 2,564.7	$3,808.8	$3,294.0	$ 2,059.6	$ 1,550.1	$ 2,256.5	$ 3,060.1
Gross profit	253.6	210.3	247.9	255.6	254.2	216.7	237.0	246.4
Earnings before extraordinary item and cumulative effect of software accounting change	43.3	23.4	28.5	37.0	57.9	20.3	24.9	31.0
Net income	43.3	23.4	28.5	37.0	50.7	20.3	24.9	26.2
Earnings per common share before extraordinary item and cumulative effect of software accounting change:								
Basic (b)(c)	$ .54	$ .29	$ .37	$ .45	$ .72	$ .25	$ .31	$ .39
Diluted (b)	.53	.29	.36	.45	.71	.25	.31	.39
Cash dividend per common share	$ .30	$ .30	$ .30	$ .30	$ .29	$ .29	$ .29	$ .29
Market price per common share:								
High	$ 26.29	$ 26.33	$ 26.25	$ 24.46	$ 18.83	$ 19.59	$ 20.59	$ 26.04
Low	23.33	23.21	22.63	22.87	17.00	17.17	19.33	20.09

(a) ALL PER SHARE AMOUNTS HAVE BEEN RESTATED FOR THE 3-FOR-2 STOCK SPLIT.
(b) RESTATED FOR ACCOUNTING CHANGE RELATED TO EARNINGS PER SHARE. SEE NOTE 1.
(c) THE SUM OF THE QUARTERLY EARNINGS PER SHARE AMOUNTS DIFFERS FROM THAT REFLECTED IN NOTE 1 DUE TO THE WEIGHTING OF COMMON SHARES OUTSTANDING DURING EACH OF THE RESPECTIVE PERIODS.

REPORT OF MANAGEMENT

The management of UtiliCorp United Inc. is responsible for the information that appears in this annual report, including its accuracy. We prepared the accompanying consolidated financial statements in accordance with generally accepted accounting principles. In addition to selecting appropriate accounting principles, we are responsible for the way information is presented and for its reliability. To report financial results we must often make estimates based on currently available information and judgements of current conditions and circumstances.

We have set up well-developed systems of internal control to ensure the integrity and objectivity of the consolidated financial information in this report. These systems are designed to provide reasonable assurance that UtiliCorp's assets are safeguarded and that the transactions are properly authorized and recorded in accordance with the appropriate accounting principles.

Through its Audit Committee, the Board of Directors participates in the process of reporting financial information. The Audit Committee selects our independent accountants. It also reviews, along with management, our financial reporting and internal accounting controls, policies and practices.

/s/ Richard Green Jr.

Richard C. Green, Jr.
Chairman of the Board
and Chief Executive Officer

/s/ James S. Brook

James S. Brook
Vice President, Controller
and Chief Accounting Officer

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO THE BOARD OF DIRECTORS AND SHAREHOLDERS OF UTILICORP UNITED INC.:

We have audited the accompanying consolidated balance sheets of UtiliCorp United Inc. and subsidiaries at December 31, 1998 and 1997 and the related consolidated statements of income, common shareowners' equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of UtiliCorp United Inc. and subsidiaries at December 31, 1998 and 1997 and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 1998 in conformity with generally accepted accounting principles.

As explained in Note 4 to the consolidated financial statements, effective October 1 , 1997, the company changed its method of accounting for internally developed software costs.

/s/ Arthur Andersen LLP

Arthur Andersen LLP
Kansas City, Missouri
February 1 , 1999

EXHIBIT 21

UtiliCorp United, Inc.
Subsidiaries
1998 Annual Report on Form 10-K

SUBSIDIARY	JURISDICTION OF INCORPORATION
West Kootenay Power, Ltd.	Province of British Columbia
UtilCo Group, Inc.	Delaware
Aquila Energy Corporation	Delaware
UtiliCorp Asia Pacific	Delaware

EXHIBIT 23

CONSENT OF INDEPENDENT ACCOUNTANTS

As Independent Public Accountants we hereby consent to the incorporation by reference of our report dated February 1, 1999, appearing on page 60 of the 1998 Annual Report to Shareholders, which is incorporated in the Form 10-K, into the company's previously filed Registration Statements on Form S-3 (Nos. 333-67067, 33-60406, 33-57167, and 33-39466) and on Form S-8 (Nos. 333-66233, 33-45525, 33-50260, 33-45074, 33-52094, and 333-19671). We also consent to the incorporation of our report dated February 1, 1999, on the Financial Statement Schedule, appearing on page 24 of the Form 10-K. It should be noted that we have not audited any financial statements of UtiliCorp United, Inc. subsequent to December 31, 1998 or performed any audit procedures subsequent to the date of our reports.

/s/ ARTHUR ANDERSEN LLP

Kansas City, Missouri
March 25, 1999

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