PNM RESOURCES

we have the power

2001 Annual Report

WE HAVE THE POWER
PNM RESOURCES
2001 ANNUAL REPORT

investor highlights: *Dollars in thousands, except per share amounts.*

	2001	2000	PERCENTAGE CHANGE	5-YEAR ANNUAL GROWTH RATE
Financial Data:				
Operating Revenues	$2,352,098	$1,611,274	46.0%	21.9%
Operating Expenses	$2,129,421	$1,478,800	44.0%	23.3%
Net Earnings Available for Common	$ 149,847	$ 100,360	49.3%	15.8%
Retained Earnings	$ 415,388	$ 296,843	39.9%	40.0%
Return on Average Common Equity	14.8%	11.1%	33.3%	8.6%
Common Share Data:				
Earnings (Basic)	$ 3.83	$ 2.54	50.8%	17.4%
Earnings (Diluted)	$ 3.77	$ 2.53	49.0%	17.1%
Book Value	$ 25.87	$ 23.64	9.4%	7.5%
Closing Price	$ 27.95	$ 26.81	4.3%	7.3%
Dividends Paid	$ 0.80	$ 0.80	N/M	17.3%
Average Shares Outstanding	39,118	39,487	-0.9%	-1.3%
Number of Employees:	2,675	2,667	0.5%	-0.5%

N/M = Not Meaningful

PNM Resources is a holding company whose primary subsidiary is PNM, an electric and gas utility based in Albuquerque, New Mexico. The company also sells power on the wholesale market in the Western U.S. PNM Resources stock is traded primarily on the NYSE under the symbol PNM.

We had a great year. Our electric and gas utility continued to provide customers with reliable service at affordable prices, while our wholesale power marketing business adapted successfully to rapid swings in prices. We're working harder and smarter than ever. Our aim is to build America's best merchant utility. **We have the power.**

we have the power to grow

our wholesale business. Efficient generating plants, strategically located on the Western power grid, coupled with years of experience in the wholesale market have enabled us to grow our wholesale revenues from $185.3 million in 1997 to $1.4 billion in 2001. To support continued expansion in our wholesale business, we are investing in two new power plants in 2002. We expect to add additional generating capacity over the next several years, as we have new customers ready to buy that additional power.

SAN JUAN GENERATING STATION – Waterflow, New Mexico

"Providing excellent customer service is our personal commitment to New Mexico."

Lynette Henry
PNM Market Services

"Customers look to us to help streamline their businesses and save money."

Manuel Quintana
Business Manager, PNM Market Services

"I'm responsible for repair and maintenance, custodial work, landscaping – it's a big job, and always changing," says Nick King, operations manager for the 900,000 square-foot Winrock Center retail mall in Albuquerque. "As my PNM account representative, Lynette makes my life easier. With her, I know I have somebody that listens to me, pays attention and gets me what I need."

quality customer service. Our core business is delivering efficient, reliable, affordable electric and gas service to the people of New Mexico. This traditional, regulated distribution business now accounts for about 40 percent of PNM revenues and provides us with a steady cash flow and predictable earnings.

Demand for electric power in our service territory has been growing at a rate above the national average over the past five years, and we expect that growth will continue in 2002 and beyond. Over the past two years, we have invested more than $200 million to expand our customer phone center and expand and upgrade our electric and gas distribution systems to boost reliability. In 2001, we installed a new, computerized outage response system designed to track outages, speed response time and keep customers better informed.

we have the power to create

shareholder value. Over the past five years, shareholders earned a 68.6 percent total return on their investment in PNM. In February 2002, the PNM Resources Board of Directors approved a 10 percent increase in the quarterly dividend, bringing the annual rate up to 88 cents per share. The increased dividend reflects financial performance in recent years and management's confidence in your company's future.

PNM Resources' ample liquidity and strong balance sheet will enable us to fund the planned expansion of generation, new investment in our utility system and future dividend increases, while maintaining our company's financial strength. We plan to continue to raise the dividend by between 8 and 10 percent a year, until dividend payout equals between 50 and 60 percent of the earnings from our regulated utility operations.

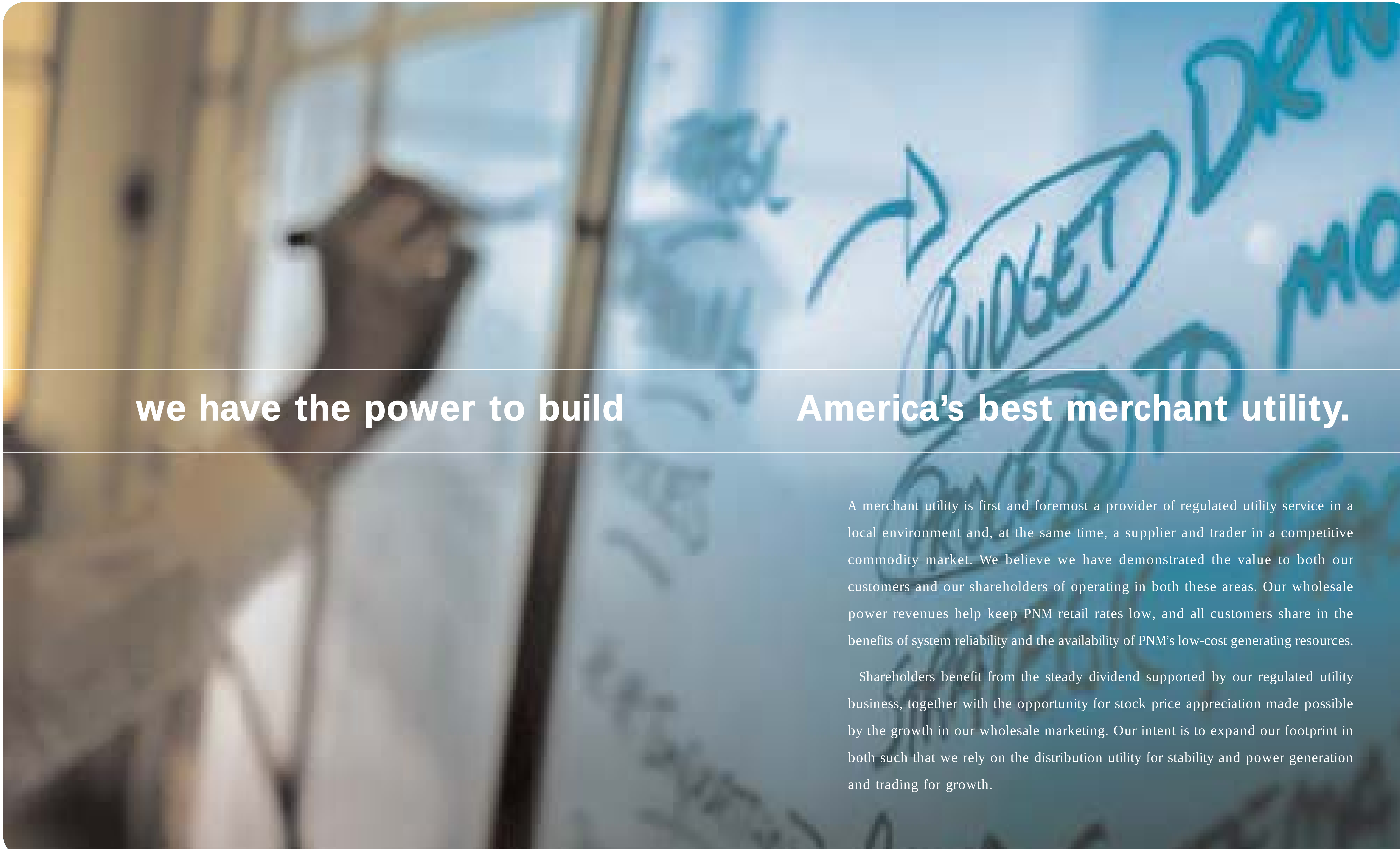
"Gifted kids need lots of hands-on experience. Given that, they're capable of learning very high-level concepts very young."
Tabitha Hall
Teacher

"We aim to encourage innovative approaches to learning that we think can really make a difference."
Diane Harrison Ogawa
PNM Foundation

Students at an Albuquerque elementary school absorb the basics of physics and engineering by building bridges with toy blocks. The idea came from teacher Tabitha Hall; the blocks were provided through a grant from the non-profit PNM Foundation. Other PNM programs support higher education, encourage energy conservation, and assist disadvantaged residential customers with their energy bills. With company support and encouragement, employees also volunteer thousands of hours of their own time to support the communities we live in.

community and environmental initiatives. As New Mexico's oldest and largest public company, PNM takes the lead in promoting the economic vitality of our home state, enhancing the quality of life in the communities we serve, and preserving the environment we all share.

PNM's systematic approach to environmental stewardship sets priorities and monitors the impact of all our business activities throughout the company, holding each operating unit accountable for its performance. Although our plants already meet or exceed all federal and state clean air and water standards, PNM continues to invest in improving its performance. Our coal-fired San Juan Generating Station has cut sulfur dioxide emissions by half over the last four years.



we have the power to build America's best merchant utility.

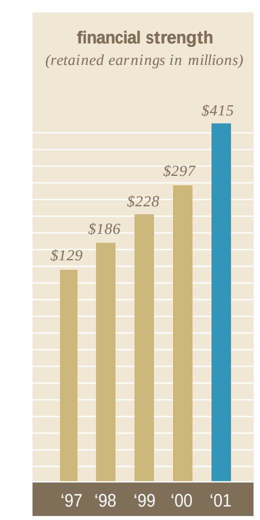
A merchant utility is first and foremost a provider of regulated utility service in a local environment and, at the same time, a supplier and trader in a competitive commodity market. We believe we have demonstrated the value to both our customers and our shareholders of operating in both these areas. Our wholesale power revenues help keep PNM retail rates low, and all customers share in the benefits of system reliability and the availability of PNM's low-cost generating resources.

Shareholders benefit from the steady dividend supported by our regulated utility business, together with the opportunity for stock price appreciation made possible by the growth in our wholesale marketing. Our intent is to expand our footprint in both such that we rely on the distribution utility for stability and power generation and trading for growth.

letter from the chairman

fellow shareholders, 2001 was the most tumultuous year I can recall in my 24 years in the energy industry. We saw extremely high price volatility in both gas and electricity markets, the California meltdown, growing debate over industry restructuring at both the federal and state level, the bankruptcy of one of the largest utilities in the United States and the collapse of the nation's largest energy trader.

Despite all this turmoil, PNM closed 2001 with the highest level of earnings in the history of the company, earning $3.77 a share on operating revenues of over $2.35 billion. Total return for PNM shareholders, including price appreciation and dividends, was a positive 7.2 percent, compared to total returns for both the Dow Jones Industrial Index and the S&P 500 Index of negative 25.8 percent and negative 11.9 percent, respectively, for the year.



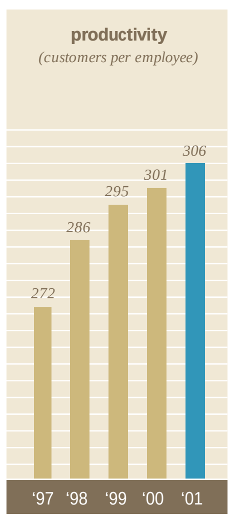
Underlying our financial performance is the hard work of the men and women of PNM:

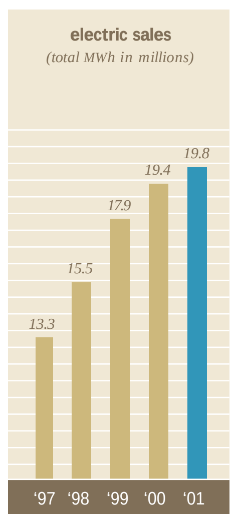
- Our quality initiative is driving service and cost improvements. "Getting Better Faster" has become a personal commitment in our service delivery business.
- We kept PNM gas customer bills down among the lowest in our region by managing our gas purchases and implementing cost-smoothing billing mechanisms, despite sharply higher gas prices in the winter of 2000-01.
- PNM retail electric rates today are 13 percent below where they were in 1985 – a 45 percent decrease when adjusted for inflation – and below the national average.
- Our wholesale trading operation weathered the electricity price storm in the West and turned in another stellar performance for the year, increasing revenues by 91 percent.
- We formed our new holding company, PNM Resources, giving us the corporate flexibility we need for future growth.

Our successes in 2001 did not come without some setbacks. Our single greatest disappointment was the collapse of our proposed acquisition of the electric utility business of Western Resources in Kansas. This outcome will not discourage us from other opportunities as they become available, however. One never succeeds by doing only that which is guaranteed.

Even that which seems guaranteed can change dramatically. We entered 2001 with just 12 months to go before we were scheduled to open our retail market in New Mexico to customer choice. That transition has now been postponed until 2007.

At the federal level, the ongoing debate on energy policy and environmental legislation could significantly change the landscape for our industry. Unfortunately, much of this debate has been clouded by the failure of Enron, confusion over the operation of competitive electricity markets, and doubts about the accuracy of audited financial reports. In this regard, it's important to remember that Enron's collapse was not caused by utility industry restructuring or by competition in the energy markets.





Competitive forces have had a marked impact on our industry, establishing a higher standard of excellence. Competition has made PNM a better company, and our customers have reaped the benefit. It has enabled the wholesale energy markets to operate effectively in the face of Enron's demise. But it has also produced some outcomes that have met with objection, primarily due to poor design.

The challenge is to find ways to gain the long-term benefits of competitive markets while providing the levels of service, predictability and convenience that consumers want. Policymakers must resist the trap of believing they can have the benefits competition brings while layering on regulation to guard against occasional unwanted outcomes.

Increased competition and the expansion of our power generation and trading operation have caused us to adopt a more systematic, enterprise-wide approach to risk management. Our asset-backed trading strategy, which bases our trades on the power available from PNM's own plants, provides a fundamental physical hedge against exposure to price volatility in the marketplace. Our risk management team, headed by CFO Max Maerki, is charged with taking a structured, rigorous approach to all the operational and strategic risks we face.

Our risk management strategy starts with a strong commitment to ethical business conduct. Our "Do the Right Thing" approach to ethics has become engrained in our corporate culture over the last 10 years. This

effort was begun by our former chairman, president and CEO John Ackerman, who retired from the PNM Board in 2001. John, who now teaches Business Ethics and Corporate Governance at the University of New Mexico, led our board in codifying the standards we now live by at PNM.

I would also like to thank former Secretary of the Interior Manuel Lujan, who also retired from our Board last year. Manny has been a trusted advisor during his tenure with the Board, and his many years of experience in Congress and as a leading figure in New Mexico proved invaluable to our company.

It is a pleasure to have two exceptional individuals recently join the Board, Martin Chavez, Ph.D., CEO of Kiodex, has extensive experience in commodity risk management, particularly in the energy area. Dr. Manuel Pacheco, President of the University of Missouri System, adds his experience in strategy and organizational management. Both of these individuals are already adding to the Board's ability to guide our company through the changes ahead.

Jeff Sterba
Chairman, President and CEO

We face significant challenges in 2002. At this writing, wholesale power prices remain below what we believe are sustainable levels. With the expiration of PNM's existing retail rate freeze in 2003, we are seeking to reach an equitable resolution that is fair to both customers and shareholders. We will also be addressing the need to add renewable resources to our generation mix.

Our successes in 2001 came through hard work in executing a sound strategy. We are committed to continuing this success in the years ahead. I thank you for your confidence in PNM Resources.

Sincerely,

Jeff Sterba
Chairman, President and CEO

financial information

PNM Resources, Inc. (the "Company") considers this annual report to contain "forward-looking statements" under Federal securities law. It is published to assist shareholders in evaluating the Company and its securities. This report does not contain all of the information material to an evaluation and should be read in conjunction with its periodic reports, proxy statement and other information the Company files with the Securities and Exchange Commission. Please refer to page 35, "Disclosure Regarding Forward-Looking Statements," for a listing of the factors which could cause the Company's actual financial results to differ materially from the prospective information provided by the Company in forward-looking statements.

selected financial data

The selected financial data should be read in conjunction with the consolidated financial statements, the notes to consolidated financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations.

	YEAR ENDED DECEMBER 31,				
	2001	2000	1999	1998	1997
(In thousands except per share amounts and ratios)					
Total Operating Revenues	$2,352,098	$1,611,274	$ 1,157,543	$ 1,092,445	$1,020,521
Earnings from Continuing Operations	$ 150,433	$ 100,946	$ 79,614	$ 95,119	$ 86,497
Net Earnings	$ 150,433	$ 100,946	$ 83,155	$ 82,682	$ 80,995
Earnings per Common Share:					
Continuing Operations	$ 3.83	$ 2.54	$ 1.93	$ 2.27	$ 2.05
Basic	$ 3.83	$ 2.54	$ 2.01	$ 1.97	$ 1.92
Diluted	$ 3.77	$ 2.53	$ 2.01	$ 1.95	$ 1.91
Cash Flow Data:					
Net cash flows provided from operating activities	$ 324,995	$ 240,947	$ 213,045	$ 210,988	$ 213,122
Net cash flows used in investing activities	$ (407,014)	$ (158,932)	$ (55,886)	$ (340,992)	$ (182,067)
Net cash flows generated (used) by financing activities	$ 385	$ (94,723)	$ (98,040)	$ 173,089	$ (33,112)
Total Assets	$2,934,638	$2,889,917	$2,723,268	$2,668,603	$2,407,410
Long-Term Debt, including Current Maturities	$ 953,884	$ 953,823	$ 988,489	$1,008,614	$ 714,345
Common Stock Data:					
Market price per common share at year end	$ 27.950	$ 26.813	$ 16.250	$ 20.438	$ 23.688
Book value per common share at year end	$ 25.87	$ 23.64	$ 21.79	$ 20.63	$ 19.26
Average number of common shares outstanding	39,118	39,487	41,038	41,774	41,774
Cash dividend declared per common share	$ 0.80	$ 0.80	$ 1.00	$ 0.60	$ 0.68
Return on Average Common Equity	14.8%	11.1%	9.5%	9.9%	10.2%
Capitalization:					
Common stock equity	50.8%	48.6%	46.7%	45.4%	52.6%
Preferred stock without mandatory redemption Requirements	0.6	0.7	0.7	0.7	0.8
Long-term debt, less current maturities	48.6	50.7	52.6	53.9	46.6
	100.00%	100.00%	100.00%	100.00%	100.00%

(See Comparative Operating Statistics which appear immediately following the Consolidated Financial Statements for additional information regarding operations.)

Due to the discontinuance of the natural gas trading operations of its Energy Services Business Unit in 1998 certain prior year amounts have been reclassified as discontinued operations.

The following is management's assessment of the Company's financial condition and the significant factors affecting the results of operations. This discussion should be read in conjunction with the Company's consolidated financial statements. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

OVERVIEW

The Company is an investor-owned holding company of energy and energy related companies. Its principal subsidiary, Public Service Company of New Mexico ("PNM"), is an integrated public utility primarily engaged in the generation, transmission, distribution and sale and trading of electricity; transmission, distribution and sale of natural gas within the State of New Mexico and the sale and trading of electricity in the Western United States. The Company's principal business segments are Utility Operations, which include Electric Services ("Electric") and Gas Services ("Gas"), and Generation and Trading Operations ("Generation and Trading"). Electric consists of two major business lines that include distribution and transmission. The transmission business line does not meet the definition of a segment for accounting purposes due to its immateriality, and for purposes of this discussion, it is combined with the distribution business line. The Company's wholly-owned subsidiary, Avistar, Inc. ("Avistar"), provides unregulated energy services.

Upon the completion on December 31, 2001, of a one-for-one share exchange between PNM and the Company, the Company became the parent company of PNM. Prior to the share exchange, the Company had existed as a subsidiary of PNM. The new holding company began trading on the New York Stock Exchange under the same PNM symbol beginning on December 31, 2001.

COMPETITIVE STRATEGY

The Company is positioned as a "merchant utility," primarily operating as a regulated energy service provider also engaged in the sale and trading of electricity in the competitive energy market place. As a utility, the Company has an obligation to serve its customers under the jurisdiction of the New Mexico Public Regulation Commission ("PRC"). As a merchant, the Company markets excess production from the utility, as well as, unregulated generation and its purchases for resale into a competitive market place. The merchant operations utilize an asset-backed trading strategy, whereby the Company's aggregate net open position for the sale of electricity is covered by the Company's excess generation capabilities. The benefits of the merchant operations are shared with retail customers based on a negotiated settlement in proportion to capacity owned, expended effort, and risk assumed. Non-regulated assets may be part of the utility company or owned by an affiliate of the utility company, which could be a subsidiary of the holding company. Currently, all non-regulated assets, except Avistar, are part of the utility. Both retail customers and shareholders benefit from this combination.

The Electric and Gas Services strategy is directed at supplying reasonably priced and reliable energy to retail customers through customer driven operational excellence, quality processes, and improved overall organizational performance.

The Generation and Trading strategy calls for increased asset-backed trading and generation capacity supported by long-term contracts, as well as improved risk management strategies. The Company's plans to increase generation calls for approximately 50% of its wholesale activity to be committed through long-term contracts, including its sales to jurisdictional customers. Such growth will be dependent on market developments, and upon the Company's ability to generate funds for the Company's expansion.

management's discussion and analysis of financial condition and results of operations

RESULTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2001 COMPARED TO YEAR ENDED DECEMBER 31, 2000

Consolidated

The Company's net earnings available to common shareholders for the year ended December 31, 2001 were $149.8 million, a 49.3% increase over net earnings of $100.4 million in 2000. This increase reflects strong market pricing in the Western United States in the first half of 2001 and continuing growth in utility operations. Earnings in both 2001 and 2000 were affected by certain special gains and non-recurring charges. These special items are detailed in the individual business segment discussions below. The following table enumerates these special gains and non-recurring charges and shows their effect on diluted earnings per share, in thousands, except per share amounts.

	2001		2000	
	Earnings	EPS (Diluted)	Earnings	EPS (Diluted)
	(Income)/Expense			
Net Earnings Available for Common Shareholders	$149,847	$3.77	$100,360	$2.53
Adjustment for Special Gains and Charges (net of income tax effects):				
Contribution to PNM Foundation	3,021	0.08	-	-
Nonrecoverable coal mine decommissioning costs	7,840	0.20	-	-
Write-off of Avistar investments	7,907	0.20	-	-
Settlement of lawsuit	-	-	(8,306)	(0.21)
Resolution of two gas rate cases	-	-	(2,808)	(0.07)
Impairment of certain tax related regulatory assets	-	-	6,552	0.16
Costs for the acquisition of long-term wholesale customer	-	-	2,740	0.07
Western Resources acquisition costs	10,859	0.27	4,047	0.10
Total	29,627	0.75	2,225	0.05
Net Earnings Available For Common Shareholders Excluding Special Gains and Charges	$179,474	$4.52	$102,585	$2.58

To adjust reported net earnings and diluted earnings per share to exclude the special gains and non-recurring charges, special gains, net of income tax expense, are subtracted from reported net earnings under Generally Accepted Accounting Principles ("GAAP") and non-recurring charges, net of income tax benefit, are added back to reported net earnings under GAAP.

The following discussion is based on the financial information presented in the Consolidated Financial Statements - Segment Information. The tables below set forth the operating results for each business segment note.

YEAR ENDED DECEMBER 31, 2001	Utility		Generation
	Electric	Gas	and Trading
Operating revenues:			
External customers	$ 559,226	$385,418	$1,405,916
Intersegment revenues	707	-	341,608
Total revenues	559,933	385,418	1,747,524
Cost of energy sold	5,102	251,296	1,280,168
Intersegment purchases	341,608	-	707
Total cost of energy	346,710	251,296	1,280,875
Gross margin	213,223	134,122	466,649
Administrative and other costs	41,275	45,973	27,969
Energy production costs	924	1,946	149,585
Depreciation and amortization	32,666	21,465	42,766
Transmission and distribution costs	37,376	31,072	553
Taxes other than income taxes	12,247	6,812	8,777
Income taxes	27,264	5,957	82,629
Total non-fuel operating expenses	151,752	113,225	312,279
Operating income	$ 61,471	$ 20,897	$ 154,370

YEAR ENDED DECEMBER 31, 2000	Utility		Generation
	Electric	Gas	and Trading
Operating revenues:			
External customers	$ 538,758	$319,924	$ 750,434
Intersegment revenues	707	-	324,744
Total revenues	539,465	319,924	1,075,178
Cost of energy sold	5,048	195,334	749,499
Intersegment purchases	324,744	-	707
Total cost of energy	329,792	195,334	750,206
Gross margin	209,673	124,590	324,972
Administrative and other costs	38,975	37,963	27,355
Energy production costs	1,208	1,485	137,202
Depreciation and amortization	31,480	19,994	41,558
Transmission and distribution costs	33,092	27,206	30
Taxes other than income taxes	13,819	8,295	11,219
Income taxes	30,516	7,605	26,083
Total non-fuel operating expenses	149,090	102,548	243,447
Operating income	$ 60,583	$ 22,042	$ 81,525

YEAR ENDED DECEMBER 31, 1999	Utility		Generation
	Electric	Gas	and Trading
Operating revenues:			
External customers	$540,868	$236,711	$371,109
Intersegment revenues	707	-	318,872
Total revenues	541,575	236,711	689,981
Cost of energy sold	4,493	112,925	414,534
Intersegment purchases	318,872	-	707
Total cost of energy	323,365	112,925	415,241
Gross margin	218,210	123,786	274,740
Administrative and other costs	52,586	49,716	26,791
Energy production costs	2,632	1,504	132,787
Depreciation and amortization	30,183	19,210	41,183
Transmission and distribution costs	31,013	28,227	23
Taxes other than income taxes	19,014	6,915	9,006
Income taxes	24,451	2,112	6,951
Total non-fuel operating expenses	159,879	107,684	216,741
Operating income	$ 58,331	$ 16,102	$ 57,999

Utility Operations

Electric

Operating revenues increased $20.5 million or 3.8% for the period to $559.9 million. Retail electricity delivery grew 2.3% to 7.3 million MWh in 2001 compared to 7.1 million MWh delivered in the prior year period, resulting in increased revenues of $8.9 million year-over-year. This volume increase was the result of load growth from economic expansion in New Mexico. In addition, revenues from third party use of the Company's transmission system increased $9.6 million as a result of additional contracts, while revenues also benefited from a $1.1 million increase in revenue from property leasing.

The following table shows electric revenues by customer class and average customers:

ELECTRIC REVENUES (*Thousands of dollars*)

	2001	2000
Residential	$187,600	$186,133
Commercial	242,372	238,243
Industrial	82,752	79,671
Other	47,209	35,418
	$559,933	$539,465
Average Customers	378,000	369,000

The following table shows electric sales by customer class:

ELECTRIC SALES *(Megawatt hours)*

	2001	2000
Residential	2,198	2,172
Commercial	3,213	3,134
Industrial	1,603	1,544
Other	241	239
	7,255	7,089

The gross margin, or operating revenues minus cost of energy sold, increased $3.6 million, which reflects the increased energy sales, transmission revenue and property leasing revenue, partially offset by higher cost for the electricity sold to retail customers. Electric exclusively purchases power from Generation and Trading at Company developed prices which are not based on market rates. These intercompany revenues and expenses are eliminated in the consolidated results.

Administrative and general costs increased $2.3 million or 5.9% for the period. This increase is primarily due to increased pension and post-retirement benefits expense resulting primarily from a reduction in expected investment returns on plan assets. Consulting expenses focused on cost control and process improvement initiatives also contributed to the increase. These increases were partially offset by lower bad debt and collection expense. By December 2000, the Company had resolved most of the problems associated with the implementation of its new billing system. As a result bad debt expense was significantly lower in 2001.

Transmission and distribution costs increased $4.3 million or 12.9% primarily due to a non-recurring increase in maintenance to improve reliability for the transmission and distribution systems.

Taxes other than income decreased $1.6 million or 11.4% reflecting favorable audit outcomes by certain tax authorities and tax planning strategies.

Gas

Operating revenues increased $65.5 million or 20.5% for the period to $385.4 million. The Company purchases natural gas in the open market and resells it at cost to its distribution customers. As a result, increased gas revenues driven by increased gas costs do not impact the Company's gross margin or earnings. The revenue increase was driven primarily by a 17.6% increase in average gas prices in the first half of 2001, resulting from increased market demand. In addition, a 3.1% volume increase and a gas rate increase, which became effective October 30, 2000 contributed to the increase. The gas rate increase added $7.8 million of revenue. Transportation volume increased 14.7% or $6.1 million. This growth was primarily attributed to gas transportation customers whose increased demand was driven by the strong power market in the Western United States during the first half of 2001. This increase is not expected to recur in 2002. Approximately $28.1 million of gas revenue in 2001 was attributable to the Company's Generation and Trading Operations and is eliminated in the consolidated results.

The following table shows gas revenues by customer and average customers:

GAS REVENUES (*Thousands of dollars*)

	2001	2000
Residential	$232,321	$191,231
Commercial	68,895	52,964
Industrial	27,519	24,206
Transportation*	20,188	14,163
Other	36,495	37,360
$385,418	$319,924	
Average Customers	443,000	435,000

The following table shows gas throughput by customer class:

GAS THROUGHPUT (*Thousands of decatherms*)

	2001	2000
Residential	27,848	28,810
Commercial	10,421	9,859
Industrial	3,920	5,038
Transportation*	51,395	44,871
Other	4,355	6,426
	97,939	95,004

*Customer-owned gas.

management's discussion and analysis of financial condition and results of operations

The gross margin, or operating revenues minus cost of energy sold, increased $9.5 million or 7.7%. This increase is due to the rate increase and higher transportation volumes, which will likely not recur in 2002, as discussed above.

Administrative and general costs increased $8.0 million or 21.1%. This increase is due to increased pension and post-retirement benefits expense resulting primarily from a reduction in expected investment returns on plan assets, consulting expenses in connection with cost control and process improvement initiatives, partially offset by decreased bad debt and collection costs.

Depreciation and amortization increased $1.5 million or 7.4% for the period due to a higher depreciable plant base.

Transmission and distribution costs increased $3.9 million or 14.2% primarily due to a non-recurring increase in maintenance to improve reliability for the transmission and distribution systems, as the Company continues to focus on improving reliability and effectiveness of its retail distribution system.

Taxes other than income decreased $1.5 million or 17.9% due to favorable audit outcomes by certain tax authorities and tax planning strategies.

Generation and Trading Operations

A spike in regional wholesale electric prices occurred in the first half of 2001 and the second half of 2000. This spike was caused by the power supply/demand imbalance in the Western United States, limited power generation capacity and increased natural gas prices. The Company does not believe that the high wholesale prices seen in 2001 and 2000 will recur in 2002. At the end of the second quarter of 2001, the market experienced falling price levels. This trend continued in the last half of 2001. As a result, market liquidity – the opportunity to buy and resell power profitably in the marketplace - also declined reflecting the bankruptcy of a major market trader and limited price volatility. The Company believes that current weak market pricing is not sustainable and that prices will adjust to more normal historical levels in the second half of 2002.

Operating revenues grew $672.3 million or 62.5% for the period to $1.7 billion. This increase in wholesale electricity sales primarily reflects the strong regional wholesale electric prices in the first half of 2001. The Company delivered wholesale (bulk) power of 12.6 million MWh of electricity this period, compared to 12.4 million MWh in the prior period. Wholesale revenues from third-party customers increased from $750.4 million to $1.4 billion, an 87.3% increase.

The following table shows sales by customer class:

GENERATION AND TRADING REVENUES BY MARKET *(Thousands of dollars)*

	2001	2000
Intersegment sales	$ 341,608	$ 324,744
Firm-requirements wholesale	24,754	15,540
Other wholesale sales*	1,381,162	734,894
	$1,747,524	$1,075,178

The following table shows sales by customer class:

GENERATION AND TRADING SALES BY MARKET *(Megawatt hours)*

	2001	2000
Intersegment sales	7,255,297	7,088,943
Firm-requirements wholesale	616,703	330,003
Other wholesale sales	11,960,397	12,022,125
	19,832,397	19,441,071

*Includes mark-to-market gains/(losses).

The gross margin, or operating revenues minus cost of energy sold, increased $141.7 million or 43.6%. The Company's margins benefit significantly from rising gas prices as most of the Company's generation portfolio is fueled by stable priced fuel sources, such as coal and uranium. As the increase in gas prices puts upward pressure on electricity prices, the profitability of the Company's stable low-cost generation increases significantly.

Margins also benefited from the Company's power trading activities. The Company buys and then resells electricity in the market generating incremental margin by taking advantage of price changes in the electricity sales market. In addition, the Company also tailors electric deliveries for its wholesale customers creating incremental margin opportunities. Generally, as market prices decline, trading volumes rise supporting margin levels in lower price electric markets. These higher margins were partially offset by a year-over-year increase in unrealized mark-to-market losses of $21.0 million which the Company recognized relating to its power trading contracts.

Administrative and general costs increased $0.6 million or 2.2% for the period. This increase is primarily due to increased pension and post-retirement benefits expense, higher power marketing expenses of $1.0 million mainly for additional incentive bonuses and certain consulting fees, and other expenses related to business development and process improvement. This increase was partially offset by lower year-over-year Generation and Trading business development costs due to significant costs related to the acquisition of a long-term wholesale customer.

Energy production costs increased $12.4 million or 9.0% for the year. The increase is primarily due to higher maintenance costs in 2001 resulting from scheduled and unscheduled outages at Palo Verde Nuclear Generating Station ("PVNGS"), San Juan Generating Station ("SJGS") and Reeves Generating Station ("Reeves"), additional incentive bonuses at SJGS, and increased generation at Reeves, one of the Company's gas generation facilities, which has a higher cost of production than the Company's coal and nuclear facilities. This increase was partially offset by lower maintenance costs at Four Corners Power Plant ("Four Corners") as a result of decreased outage time. A significant unscheduled outage occurred in the fall of 2001 at SJGS. The Company took advantage of the outage to accelerate its outage scheduled for the spring of 2002. As a result, maintenance costs and the related lost market potential of the accelerated outage will be avoided in the spring of 2002.

Depreciation and amortization increased $1.2 million or 2.9% for the period due to a higher depreciable plant base.

Taxes other than income decreased $2.4 million or 21.8% as a result of favorable audit outcomes by certain tax authorities and tax planning strategies.

Unregulated Businesses

In July 2001, the Board of Directors of Avistar decided to wind down all unregulated operations except for Avistar's Reliadigm business unit, which provides maintenance solutions and technologies to the electric power industry. Avistar had previously divested itself of its Energy Partners business unit and liquidated Axon Field Services and Pathways Integration. This divestiture was largely in response to market disruptions caused by the California energy crisis. In addition, the transfer of operation of the Sangre de Cristo Water Company to the City of Santa Fe was completed in the third quarter. All remaining non-Reliadigm investments were written-off with the exception of Avistar's investment in Nth Power, an energy related venture capital fund. These write-downs reflect the significant decline in the technology market and bankruptcy of these investees. The Company recorded non-operating charges of $13.1 million to reflect these activities and the impairment of its Avistar investments.

Due to the cessation of much of Avistar's historic operations, business activity declined significantly. Revenues decreased 30.8% for the period to $1.5 million. Operating losses for Avistar decreased from $4.6 million in the prior year period to $4.2 million in the current year period primarily due to decreased costs as a result of the shutdown of certain operations. In January 2002, Avistar was dividended to PNM Resources by PNM.

Corporate

Corporate administrative and general costs, which represent costs that are driven exclusively by corporate-level activities, decreased $1.4 million for the period to $32.1 million. This decrease was due to lower bonus expense in 2001 and reorganizational costs incurred in 2000 that did not occur in 2001 due to the delay in separating Utility Operations from Generation and Trading Operations. These cost improvements were partially offset by higher legal costs associated with routine business operations and increased pension and post-retirement benefit expense.

Other Non-Operating Costs

Other income and deductions, net of taxes, decreased $41.3 million for the period to a loss of $7.4 million. On a pre-tax basis in 2000, the Company recognized gains of $13.8 million related to the settlement of a lawsuit, $4.5 million for the reversal of certain reserves associated with the resolution of two gas rate cases and $2.4 million related to the Company's hedge of certain non-qualified retirement plan trust assets. In the current year, the Company recorded pre-tax charges of $13.1 million to write-off certain permanently impaired Avistar investments and $13.0 million of non-recoverable coal mine decommissioning

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costs previously established as a regulatory asset. The Company will continue to evaluate the recoverability of regulatory assets as the rate making process occurs and will identify its stranded costs, if any, when it files its new transition plan that is due by January 1, 2005. The current year results also include the following pre-tax items: a donation of $5.0 million to the PNM Foundation; unrecoverable costs of $2.3 million related to an abandoned transmission line expansion project; a year-over-year decrease in investment income of $5.6 million on the PVNGS decommissioning trust assets; and increased costs of $5.5 million related to the Company's terminated acquisition of Western Resources' electric utility operations, partially offset by $3.4 million of equity income from a passive investment. Total costs for the year ended December 31, 2001 related to the Company's terminated acquisition of Western Resources were $18.0 million pre-tax. The Company has expensed all costs related to the terminated transaction to date.

The Company's consolidated income tax expense was $81.1 million in the twelve months ended December 31, 2001, an increase of $6.7 million for the year. The impact of higher earnings was partially mitigated by the reversal of $6.6 million of valuation allowances taken against certain income tax related regulatory assets in 2000 that the Company determined would continue to be recoverable in rates largely due to the delay in the implementation of deregulation. The Company's effective income tax rates for the years ended 2001 and 2000 were 35.02% and 42.41%, respectively. Excluding the impact of the valuation reserve changes, the Company's effective income tax rates for the years ended 2001 and 2000 were 37.85% and 38.67%, respectively. The decrease in the effective rate was primarily due to the favorable tax treatment received on the 2001 equity earnings discussed above.

YEAR ENDED DECEMBER 31, 2000 COMPARED TO YEAR ENDED DECEMBER 31, 1999

Consolidated

The Company's net earnings available to common shareholders for the year ended December 31, 2000 were $100.4 million, a 22% increase over net earnings of $82.6 million in 1999. This increase reflects strong market pricing in the Western United States in the second half of 2000 and continuing growth in utility operations. Earnings in both 2000 and 1999 were affected by certain special gains and charges. These special items are detailed in the individual business segment discussions below. The following table enumerates these special gains and charges and shows their effect on diluted earnings per share, in thousands, except per share amounts.

	2000		1999	
	Earnings	EPS (Diluted)	Earnings	EPS (Diluted)
	(Income)/Expense			
Net Earnings Available for Common Shareholders	$100,360	$2.53	$82,569	$2.01
Adjustment for Special Gains and Charges (net of income tax effects):				
Settlement of lawsuit	(8,306)	(0.21)	-	-
Resolution of two gas rate cases	(2,808)	(0.07)	-	-
Impairment of certain tax related regulatory assets	6,552	0.16	-	-
Costs for the acquisition of long-term wholesale customer	2,740	0.07	-	-
Western Resources acquisition costs	4,047	0.10	-	-
Equity income from a passive investment	-	-	(4,180)	(0.10)
Mine closure activities	-	-	(1,227)	(0.03)
Bad debt costs associated with system implementation problems	-	-	4,890	0.12
Cumulative effect of an accounting change	-	-	(3,541)	(0.09)
Total	2,225	0.05	(4,058)	(0.10)
Net Earnings Available For Common Shareholders Excluding Special Gains and Charges	$102,585	$2.58	$78,511	$1.91

To adjust reported net earnings and diluted earnings per share to exclude the special gains and non-recurring charges, special gains, net of income tax expense, are subtracted from reported net earnings under GAAP and non-recurring charges, net of income tax benefit, are added back to reported net earnings under GAAP.

Utility Operations

Electric

Operating revenues declined $2.1 million or 0.4% for the year to $539.5 million due to the implementation in late July 1999 of the rate order lowering rates by $22.2 million year-over-year. This was mostly offset by increased retail electricity delivery of 7.1 million MWh compared to 6.8 million MWh delivered in the prior year period, a 4.2% improvement which increased revenues $21.8 million year-over-year. This increased volume was the result of warm temperatures and load growth.

The following table shows electric revenues by customer class:

ELECTRIC REVENUES *(Thousands of dollars)*

	2000	1999
Residential	$186,133	$184,088
Commercial	238,243	238,830
Industrial	79,671	85,828
Other	35,418	32,829
	$539,465	$541,575
Average Customers	369,000	361,000

The following table shows electric sales by customer class:

ELECTRIC SALES *(Megawatt hours)*

	2000	1999
Residential	2,172	2,028
Commercial	3,134	2,982
Industrial	1,544	1,559
Other	239	235
	7,089	6,804

The gross margin, or operating revenues minus cost of energy sold, decreased $8.5 million. This decline reflects the rate reduction discussed above. Electric exclusively purchases power from Generation and Trading at Company developed prices which are not based on market rates.

Administrative and general costs decreased $13.6 million or 25.9% for the year. This decrease is due to non-recurring Year 2000 ("Y2K") compliance costs and non-recurring costs related to the Company's implementation of its new customer billing system in 1999. In addition, in 1999, as a result of significant increases in delinquent accounts due to system implementation problems, the Company incurred additional bad debt costs of $5.5 million above its normal experience rate. Bad debt expense in 2000 was $4.9 million, a 29.9% decline for the year.

Energy production costs decreased $1.4 million or 54.1% for the year primarily due to non-recurring Y2K compliance costs in 2000.

Depreciation and amortization increased $1.3 million or 4.3% for the year. The increase is due to the impact of amortizing the costs of the new customer billing system, which has a five-year amortization life, and depreciating the expansion of the electric distribution system.

Transmission and distribution costs increased $2.1 million or 6.7% for the year primarily due to increased scheduled maintenance of transmission lines and the addition of station related equipment for reliability purposes. This increase in scheduled maintenance continued in 2001.

Taxes other than income decreased $5.2 million or 27.3% due to a change in the recognition of electric franchise fees collected from customers and payable to municipalities, partially offset by the impact of the implementation of the new

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customer billing system on the collection of certain taxes and an increase in expected tax liabilities. Franchise fees were a part of the Company's rate structure in 1999. In 2000, they were unbundled from the rate structure. As a result, the Company now passes through directly to customers the franchise fees charged by municipalities and does not incur expense or generate revenues as a result of collecting the fees.

Gas

Operating revenues increased $83.2 million or 35.2% for the year to $319.9 million. The Company purchases natural gas in the open market and resells it at cost to its distribution customers. As a result, increased gas revenues driven by increased gas costs do not impact the Company's gross margin or earnings. The increase was driven by a 31.3% increase in gas prices in the later months of 2000 as a result of increased market demand, a 3.0% volume increase.

The following table shows gas revenues by customer class:

GAS REVENUES *(Thousands of dollars)*

	2000	1999
Residential	$191,231	$152,266
Commercial	52,964	37,337
Industrial	24,206	8,550
Transportation*	14,163	12,390
Other	37,360	26,168
	$319,924	$236,711
Average customers	435,000	426,000

The following table shows gas throughput by customer class:

GAS THROUGHPUT *(Thousands of decatherms)*

	2000	1999
Residential	28,810	32,121
Commercial	9,859	11,106
Industrial	5,038	2,338
Transportation*	44,871	40,161
Other	6,426	6,538
	95,004	92,264

*Customer-owned gas.

The gross margin, or operating revenues minus cost of energy sold, increased $0.8 million or 0.7%. This increase is due to higher retail customer distribution volumes on which the Company earns cost of service revenues.

Administrative and general costs decreased $11.8 million or 23.6%. This decrease is mainly due to non-recurring Y2K compliance costs, customer billing system costs and lower associated bad debt costs. The Electric and Gas Services share the same billing system, and Gas Services experienced the same delinquency problems discussed above in the "Electric" results of operations. As a result, in 1999, the Company incurred additional bad debt costs of $2.1 million above its normal experience rate. However, bad debt expense did not significantly decline in 2000 as the Company increased its bad debt costs by approximately $2.0 million in anticipation of a higher than normal delinquency rate driven by the significantly higher natural gas prices experienced in November and December 2000. This trend is similar to historic collection trends associated with past gas price spikes.

Depreciation and amortization increased $0.8 million or 4.1% for the year. The increase is due to the impact of amortizing the costs of a new customer billing system and depreciating the expansion of the gas transmission system.

Transmission and distribution costs decreased $1.0 million or 3.6% primarily due to non-recurring Y2K compliance costs.

Taxes other than income increased $1.4 million or 20.0% primarily due to higher tax liabilities and the impact of the implementation of the new customer billing system on the collection of certain taxes.

Generation and Trading Operations

Operating revenues grew $385.2 million or 55.8% for the year to $1.08 billion. This increase in wholesale electricity sales reflects strong regional wholesale electric prices caused by a warm summer, limited power generation capacity, increasing natural gas prices and the power supply imbalance in the Western United States. These factors contributed to unusually high wholesale prices which the Company does not believe to be sustainable in the long-term, although these factors continued to affect markets in the first half of 2001. The Company delivered wholesale (bulk) power of 12.4 million MWh this period compared to 11.2 million MWh delivered last year, an increase of 10.6%. The MWh increase is attributable to increased trading activity during the year. Wholesale revenues from third-party customers increased from $371.1 million to $750.4 million, a 102.2% increase. The increase was largely price driven.

The following table shows revenues by customer class:

GENERATION AND TRADING OPERATIONS REVENUES BY MARKET *(Thousands of dollars)*

	2000	1999
Intersegment sales	$324,744	$318,872
Firm-requirements wholesale	15,540	7,046
Other wholesale sales*	734,894	364,063
	$1,075,178	$689,981

The following table shows sales by customer class:

GENERATION AND TRADING OPERATIONS SALES BY MARKET *(Megawatt hours)*

	2000	1999
Intersegment sales	7,088,943	6,803,583
Firm-requirements wholesale	330,003	179,249
Other wholesale sales	12,022,125	10,992,372
	19,441,071	17,975,204

*Includes mark-to-market gains/(losses).

The gross margin, or operating revenues minus cost of energy sold, increased $50.2 million or 18.3%. Higher margins were partially offset by $8.5 million of losses associated with the Company's assessment of risk in the wholesale market and unrealized mark-to-market losses of $4.8 million which the Company recognized relating to its power trading contracts. These items were recorded as revenue adjustments.

Administrative and general costs increased $3.6 million or 2.1% for the year. This increase is due to a one-time charge of $4.5 million in connection with the acquisition of a new, long-term wholesale customer and an increase in bad debt costs, partially offset by non-recurring Y2K compliance costs and lower legal costs related to a lawsuit settlement involving the Company's decommissioning trust which was settled in August 2000. The settlement was recorded as other income.

Energy production costs increased $4.4 million or 3.3% for the year. These costs are generation related. The increase is due to higher maintenance costs resulting from scheduled outages at San Juan Unit 3 and Four Corners Unit 4, which were partially offset by lower PVNGS employee costs as a result of additional employee incentive and retiree healthcare costs in the prior year that did not recur in 2000 and additional PVNGS billings in 1999 for 1998 expenses as a result of an audit by the station owners.

Taxes other than income increased $2.2 million or 24.6% due to higher tax liabilities.

Unregulated Businesses

Avistar contributed $2.2 million in revenues for the year compared to $8.9 million in the comparable prior year period due to lower business volumes resulting from slow developing markets associated with Avistar's new product offerings. Operating losses for Avistar increased from $4.4 million in the prior year to $6.6 million in the current year.

Corporate

Corporate administrative and general costs, which represent costs that are driven exclusively by corporate-level activities, increased $8.0 million for the year to $33.5 million. This increase was due to additional administrative and consulting expenses for strategic initiatives, higher legal costs and reorganizational costs incurred in anticipation of separating utility operations under the Restructuring Act.

Other Non-Operating Costs

Other income and deductions, net of taxes, increased $4.2 million for the year to $34.4 million due to certain special gains. The Company recognized on a pre-tax basis $13.2 million related to the settlement of a lawsuit and $4.6 million before income taxes associated with the resolution of two gas rate cases. The current year also had increased mark-to-market gains on the Company's hedge of its investments for nuclear decommissioning and certain post retirement benefits. These gains were partially offset by $6.7 million of costs related to the Company's terminated Western Resources transaction. In addition, other income and deductions included a valuation loss recognized for Avistar's AMDAX.com investment, and expenses related to the transfer of the operation of the City of Santa Fe's water system to the municipality. In 1999, other income and deductions included gains, on a pre-tax, basis of $4.2 million of equity income from a passive investment and $2.0 million from closing down certain coal mine reclamation activities in an inactive subsidiary.

Net interest charges decreased $4.7 million for the period to $65.9 million primarily as a result of the retirement of $31.6 million of senior unsecured notes in June and August 1999 and $32.8 million in January 2000.

The Company's consolidated income tax expense, before the cumulative effect of an accounting change, was $74.3 million, an increase of $32.0 million for the year. The Company's 2000 income tax effective rate, before the cumulative effect of the accounting change, was 42.41%. Included in the Company's 2000 income tax expense is the write-off of $6.6 million of income tax-related regulatory assets. Excluding the write-off of income tax-related regulatory assets, the Company's effective tax rate was 38.67%. The Company's 1999 effective tax rate was 34.70%. The increase in the rate was primarily due to the favorable tax treatment received on the 1999 equity earnings in other income and deductions discussed above.

FUTURE EXPECTATIONS

Because of the wholesale market price decline in the Western United States that began in the second half of 2001, the Company's 2002 earnings are not expected to reach 2001 levels. On January 23, 2002, the Company announced that it expects its 2002 earnings to be at the lower end of the previously identified range of $3.00 to $3.50 per share. Wholesale prices in the West currently remain at lower levels than the Company believes likely to prevail through the remainder of 2002; however, the Company expects this reduced pricing environment to continue through much of the first and second quarters. The Company's view is based on a return to normal weather, a beginning of economic recovery by summer and the reemergence of liquidity in the wholesale market that was impacted by the bankruptcy of a major trader and credit quality reduction of other market traders. Accordingly, the Company believes that the lower end of the range, $3.00 per share in earnings, is achievable for 2002, and the first quarter earnings are likely to be consistent with trends from the first quarter in 2000. However, if wholesale prices in the West do not increase as forecasted by the Company, the Company's earnings are likely to be lower than its identified range of $3.00 to $3.50. The calculation of future expected earnings is subject to numerous variables, including on and off-peak wholesale demand, retail load needs, natural gas prices, generating resource availability, the current position of the Company's trading portfolio and general economic conditions.

As a result of the reduced pricing environment, many generators have announced the cancellation of previously planned projects. The Company expects that forward prices will again move upwards in future periods as result of under building. As the Company adds new generation resources, it is expected that earnings will trend upwards as sales volumes grow. This growth is expected to be in high single digits over the long-term. The Company's strategic plan to add generation resources will provide electric wholesale volume growth beginning in 2002 and in the later years of the forecast.

This discussion of future expectations is forward-looking information within the meaning of Section 21E of the Securities

Exchange Act of 1934. The achievement of expected results is dependent upon the assumptions described in the preceding discussion, and is qualified in its entirety by the Private Securities Litigation Reform Act of 1995 disclosure- (see "Disclosure Regarding Forward Looking Statements" below) - and the factors described within the disclosure that could cause the Company's actual financial results to differ materially from the expected results enumerated above.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in conformity with GAAP requires the Company to select and apply accounting policies that best provide the framework to report the Company's results of operations and financial position. The selection and application of those policies require management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. The judgments and uncertainties inherent in this process affect the application of those policies. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions. Management has identified the following accounting policies that it deems critical to the portrayal of the Company's financial condition and results and that involve significant subjectivity. Management believes that its selection and application of these policies best represent the operating results and financial position of the Company. The following discussion provides information on the processes utilized by management in making judgments and assumptions as they apply to its critical accounting policies.

Revenue Recognition

The Company recognizes revenues in the period of delivery. The Company's Utility Operations are required to estimate revenues for unbilled services when its billing cycle does not match the calendar-end reporting period. Management's estimates are based on models which utilize actual units delivered and the applicable rate structure.

Utility Operation's gas operating revenues exclude adjustments for differences in gas purchase costs that are above or below levels included in base rates but are recoverable under the mechanism established by the PRC. Utility Operations recognize this adjustment when it is permitted to bill under PRC guidelines. Utility Operations, also, periodically hedge natural gas purchases to limit commodity price volatility. Unrealized gains and losses from natural gas-related swaps, futures and forward contracts are deferred and recognized as the natural gas is sold and is recovered through gas rates charged to customers.

The Company enters into energy trading contracts to take advantage of market opportunities associated with the purchase and sale of electricity. Unrealized gains and losses resulting from the impact of price movements on Generation and Trading Operations' contracts are recognized as adjustments to Generation and Trading Operations operating revenues. These adjustments are based on market prices that are actively quoted.

Financial Instruments

Under the derivative accounting rules and the related accounting rules for energy trading activities, the Company accounts for its various financial derivative instruments for the purchase and sale of energy differently based on Management's intent when entering into the contract. Energy trading contracts are recorded at fair market value at each period end. The changes in fair market value are recognized in earnings. Non-trading contracts must be accounted for as derivatives and recorded in the balance sheet as either an asset or liability measured at their fair value. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting or normal purchase and sale criteria are met. Should an energy transaction qualify as a hedge, fair market value changes from period to period are recognized on the balance sheet with a corresponding charge to other comprehensive income. Gains or losses are recognized when the hedged transaction occurs. Normal purchases and sales are not marked-to-market but rather recorded in results of operations when the underlying transaction occurs.

The market prices used to value the Company's energy trading contracts are based on closing exchange prices and over-the-counter quotations. As of December 31, 2001, the Company does not have any outstanding contracts that were valued using methods other than quoted prices. The Company did not change its methods for valuing its trading contracts in 2001 as compared to 2000. The Company recognized a $25.8 million loss related to its mark-to-market adjustment in 2001. This represents the net change in the Company's mark-to-market adjustment for its trading contracts from December 31, 2000 to December 31, 2001.

The following table summarizes the Company's trading portfolio at December 31 (*in thousands*):

	2001	2000
Face value of contracts	$ (41,193)	$ (6,314)
Market value of contracts	(10,753)	(1,672)
Mark-to-market loss	$ (30,440)	$ (4,642)

The trading portfolio positions at December 31, 2001 and 2000 represent net liabilities after netting all open purchase and sale contracts. Because the contractual amounts required to settle the net liability were greater than the current market values of the contracts, the Company recognized mark-to-market losses for the differences in 2001 and 2000.

As of December 31, 2001, a decrease in market pricing of the Company's trading contracts by 10% would have resulted in a decrease in net earnings of less than 1%. Conversely, an increase in market pricing of the Company's trading contracts by 10% would have resulted in an increase in net earnings of less than 1%.

At December 31, 2001, the market value of the Company's normal sales and purchases of electricity was a $1.7 million liability using the valuation methods described above. If these transactions were classified as trading or did not meet the definition of normal under the accounting rules for derivatives, the Company would have recognized unrealized gains of $18.2 million as an adjustment to Generation and Trading Operations operating revenues based on the change in fair value of these contracts from January 1, 2001 to December 31, 2001.

In addition to the fair market valuation described above, the Company provides for losses due to market and credit risk in the electric wholesale marketplace based on its assessment of counterparty default risk. This assessment is based on a methodology that considers the credit ratings of the Company's counterparties, the price volatility in the marketplace, the fair market value of all contracts outstanding and management's evaluation of market trends that are expected to impact market risk. The resulting amount is recorded as an adjustment to revenue. Increases in market prices, increases in an individual counterparty's credit position and general economic conditions which may impact the credit ratings of the Company's counterparties will generally result in an increased market volatility and credit risk and a corresponding reduction to revenues.

Regulatory Assets and Liabilities

The accounting rules for rate regulated entities require a company to reflect the effects of regulatory decisions in its financial statements. In accordance with these accounting rules, the Company has deferred certain costs that are rate recoverable and recorded certain liabilities for amounts to be returned to retail customers pursuant to the rate actions of the PRC and its predecessor, and the Federal Energy Regulatory Commission ("FERC"). Substantially all of the Company's regulatory assets and regulatory liabilities are reflected in rates charged to retail customers or have been addressed in a regulatory proceeding. To the extent that management concludes that the recovery of a regulatory asset is no longer probable due to changes in regulatory treatment, the effects of competition or other factors, the amount would be recorded as a charge to earnings as recovery is no longer probable. The Company currently has fixed electricity rates for jurisdictional service purposes until January 2003. If the present rates were materially reduced, management would need to re-evaluate the recoverability of its regulatory assets. If management were to determine that the new rate structure would not be sufficient to recover these regulatory assets, the Company would be required to record a charge for the portion of the costs that were not recoverable.

The Company has discontinued the application of regulatory accounting as of December 31, 1999, for the generation portion of its business effective with the passage in New Mexico of the Electric Utility Industry Restructuring Act of 1999. The Company evaluates these assets under the same impairment rules that it uses to evaluate tangible long-lived assets. In 2001, the Company determined certain costs would not be recovered and recorded a charge of $13.1 million to earnings for these amounts. The Company believes that it will recover costs associated with its remaining stranded assets, including asset closure costs, through a non-bypassable charge as permitted by the Restructuring Act, or in future rate cases prior to implementation of customer choice. If management were to determine that the expected non-bypassable charge or other rate treatment would not be sufficient to recover these costs, the Company would be required to record a charge to earnings for that portion of the costs that were not recoverable.

Asset Impairment

The Company regularly evaluates the carrying value of its tangible long-lived assets in relation to their future undiscounted cash flows to assess recoverability in accordance with accounting rules. Impairment testing of power generation assets is performed periodically in response to changes in market conditions resulting from industry deregulation and other market trends. Power generation assets used to supply jurisdictional and wholesale markets are evaluated on a group basis using future undiscounted cash flows based on current open market price conditions. The Company also has generation assets that are used for the sole purpose of reliability. These assets are tested as an individual group. Power generation assets held under operating leases are not currently evaluated for impairment as prescribed by current GAAP. The Company's estimate of future undiscounted cash flows is based on its assumptions of future market trends for the price of electricity such as demand, pricing and volatility. Adverse developments in the wholesale electricity market that lead to less favorable assumptions about future market trends could result in an impairment of the Company's power generation assets.

Contingent Liabilities

There are various claims and lawsuits pending against the Company and certain of its subsidiaries. The Company has recorded a liability where the effect of litigation can be estimated and where an outcome is considered probable. Management's estimates are based on its knowledge of the relevant facts at the time of the issuance of the Company's Consolidated Financial Statements. Subsequent developments could materially alter management's assessment of a matter's probable outcome and the estimate of the Company's liability.

Environmental Issues

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, current laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, the Company records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2001, the Company had cash and short-term and long-term investments of $176.8 million compared to $107.7 million in 2000. The Company's long-term investments are highly liquid though its intent is to hold them longer than one year.

Cash provided from operating activities in the year ended December 31, 2001 was $325.0 million, an increase of $84.0 million from 2000. This increase was primarily the result of increased profitability. Contributing to this increase was the recovery of the cost of purchased gas from utility customers deferred in accordance with PRC regulations. In addition, the Company was not required to make the first quarter 2001 estimated federal income tax payment because of an automatic extension granted by the IRS to taxpayers in several counties in New Mexico as a result of wildfires in 2000. This payment was made in January 2002. Partially offsetting these cash inflows was the impact of lower wholesale electric and gas prices at year end 2001, resulting in a decrease in accounts payable; however, these same price decreases led to an offsetting decrease in accounts receivable. This market effect resulted in a net cash outflow of $60.5 million, year-over-year.

Cash used for investing activities was $407.0 million in 2001 compared to $158.9 million in 2000. This increase reflects the movement of $150.0 million of cash to investments with longer maturities, ranging from one to three years, and greater yields. In addition, cash used for investing activities includes construction expenditures related to the Company's announced new generating plants of $103.4 million in 2001 compared to $13.0 million for similar expenditures in 2000 and expenditures of $14.0 million in 2001 related to the acquisition of certain transmission assets and other related investing activities compared to $5.8 million for similar expenditures in 2000. The Company continues to make significant investments in its generation portfolio.

Cash generated by financing activities was $0.4 million compared to $94.7 million of cash used in 2000. Financing activities in 2001 were primarily short-term borrowings for liquidity reasons, offset by cash payments for dividend requirements. The use of cash in 2000 reflects the repurchase of $34.7 million of senior unsecured notes at a cost of $32.8 million and common stock repurchases of $27.9 million.

Pension and Other Postretirement Benefits

In 2001, the investment market experienced significant declines due to various reasons. In addition, the future outlook for the investment market is not expected to improve in the short term. As a result, the Company adjusted the expected rate of return on its pension and other postretirement benefit plans assets. For the year ended December 31, 2001, the Company's net periodic benefit cost assumed a 7.75% rate of return as compared to 9.00% in the prior year. The rate adjustment reflects the Company's outlook for asset returns after considering the events of September 11, 2001 and the impact of asset losses recognized in the September 30, 2001 plan valuation. This change resulted in an increase of $4.2 million in the Company's recorded net periodic benefit expense. In addition, increases in the health care cost trend contributed an additional $3.2 million of increased costs. Total net periodic benefit cost for all plans was $11.3 million in 2001 as compared to $4.6 million in 2000. The actual return on the plan's assets for the year ended December 31, 2001 was a loss of $36.2 million. As a result, the Company recorded a tax effected decrease in other comprehensive income of $28.9 million.

The actual losses recorded in other comprehensive income will be recognized in the Company's future results of operations to the extent that future calculations of the net periodic benefit expense's assumed rate of return reflects the losses. The accounting rules for pension plans and other postretirement benefits allow investment gains and losses to be recognized in a systematic and rational method. This methodology reduces the periodic impact of market volatility.

In January 2002, the Company made an aggregate contribution of $23.5 million to fund the pension and other postretirement benefit plans. The effect of this contribution will be to reduce the impact that the actual investment losses will have on the Company's future net periodic benefit cost. In addition, the Company believes that its expected rate of return in 2002 will be at historical levels.

Capital Requirements

Total capital requirements include construction expenditures as well as other major capital requirements and cash dividend requirements for both common and preferred stock. The main focus of the Company's construction program is upgrading generation systems, upgrading and expanding the electric and gas transmission and distribution systems and purchasing nuclear fuel. In addition, the Company anticipates significant expenditures to expand its wholesale generation capabilities. Projections for total capital requirements for 2002 are $409 million and projections for construction expenditures for 2002 are $391 million. For 2002-2006 projections, total capital requirements are $1.9 billion and construction expenditures are $1.8 billion, including the combustion turbines discussed below. These estimates are under continuing review and subject to on-going adjustment.

The Company has committed to purchase five combustion turbines at a total cost of $151.3 million. The turbines for three planned power generation plants with a combined capacity of 657 MWs. The estimated cost of construction of the plants is approximately $400.3 million. The Company has expended $103.4 million as of December 31, 2001. In November 2001, the Company broke ground for Afton Generating Station ("Afton"), a 135 MW natural gas fired generating plant on a site in Southern New Mexico. This facility is expected to be operational by October 2002. Currently, the Company plans to expand the facility to 225 MW by the end of 2003. In February 2002, the Company also broke ground to build Lordsburg Generating Station ("Lordsburg"), an 80 MW natural gas fired generating plant in Southwestern New Mexico. This facility is expected to be operational by July 2002. The planned plants are part of the Company's ongoing competitive strategy of increasing generation capacity over time. The costs of these plants are not anticipated to be added to the rate base.

The Company's construction expenditures for 2001 were entirely funded through cash generated from operations. To meet its capital needs for its planned expansion of its generation capabilities, the Company expects that it will have to access the capital markets. Otherwise, the Company anticipates that internal cash generation and current debt capacity will be sufficient to meet all its other capital requirements for the years 2002 through 2006. To cover the difference in the amounts and timing of cash generation and cash requirements, the Company intends to use short-term borrowings under its liquidity arrangements.

Liquidity

At March 1, 2002, PNM had $170 million of available liquidity arrangements, consisting of $150 million from an unsecured revolving credit facility ("Credit Facility"), and $20 million in local lines of credit. The Credit Facility will expire in March 2003. There were $75.0 million in borrowings as of March 1, 2002. In addition, the Company has a $20.0 million reciprocal borrowing agreement with PNM and $25.0 million in local lines of credit.

The Company's ability to finance its construction program at a reasonable cost and to provide for other capital needs is largely dependent upon its ability to earn a fair return on equity, results of operations, credit ratings, regulatory approvals and financial and wholesale market conditions. Financing flexibility is enhanced by providing a high percentage of total capital requirements from internal sources and having the ability, if necessary, to issue long-term securities, and to obtain short-term credit.

PNM's credit outlook is considered positive by Moody's Investor Services ("Moody's") and stable by Standard and Poors ("S&P"). Previously, in connection with PNM's announcement of its agreement to acquire Western Resources' electric utility operations, S&P, Moody's and Fitch Ratings ("Fitch") placed the PNM's securities ratings on negative credit watch pending review of the transaction. As a result of events which led the Company to conclude the acquisition could not be accomplished, ultimately leading PNM to terminate the transaction in January 2002, S&P, Moody's and Fitch removed the Company from negative credit watch. PNM is committed to maintaining its investment grade. S&P currently rates PNM's senior unsecured notes

("SUNs") and its Eastern Interconnection Project ("EIP") senior secured debt "BBB-"and its preferred stock "BB". Moody's rates PNM's SUNs and senior unsecured pollution control revenue bonds "Baa3"; and preferred stock "Ba1". The EIP senior secured debt is also rated "Ba1". Fitch rates PNM's SUNs and senior unsecured pollution control revenue bonds "BBB-,"PNM's EIP lease obligation "BB+"and PNM's preferred stock "BB."Investors are cautioned that a security rating is not a recommendation to buy, sell or hold securities, that it may be subject to revision or withdrawal at any time by the assigning rating organization, and that each rating should be evaluated independently of any other rating.

Long-term Obligations and Commitments

The following table shows PNM's long-term debt and operating leases as of December 31, 2001. As of March 1, 2002, the holding company has no long-term obligations except those consolidated with PNM.

PAYMENTS DUE *(In thousands)*

CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN 1 YEAR	2-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Long-Term Debt	953,884	-	-	268,420	685,464
Operating Leases	532,954	32,095	66,162	70,356	364,341
Total Contractual Cash Obligations	1,486,838	32,095	66,162	338,776	1,049,805

PNM leases interests in Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. In 1998, PNM established PVNGS Capital Trust ("Capital Trust"), for the purpose of acquiring all the debt underlying the PVNGS leases. PNM consolidates Capital Trust in its consolidated financial statements. The purchase was funded with the proceeds from the issuance of $435 million of SUNs, which were loaned to Capital Trust. Capital Trust then acquired and now holds the debt component of the PVNGS leases. For legal and regulatory reasons, the PVNGS lease payment continues to be recorded and paid gross with the debt component of the payment returned to PNM via Capital Trust. As a result, the net cash outflows for the PVNGS lease payment were $12.4 million in 2001. The table above reflects the net lease payment.

PNM's other significant operating lease obligations include the Eastern Interconnect Project ("EIP"), a transmission line with annual lease payments of $7.3 million and a power purchase agreement for the entire output of Delta Persons Generating Station ("Delta"), a gas-fired generating plant in Albuquerque, New Mexico with imputed annual lease payments of $6.0 million.

The Company's off-balance sheet obligations are limited to PNM's operating leases and certain financial instruments related to the purchase and sale of energy (see below). The present value of PNM's operating lease obligations for PVNGS Units 1 and 2, EIP and the Delta PPA was $224 million as of December 31, 2001.

PNM has entered into various long-term power purchase agreements obligating it to make aggregate fixed payments of $30.3 million plus the cost of production and a return. These contracts expire December 2006 through July 2010. In addition, PNM is obligated to sell electricity for $158.1 million in fixed payments plus the cost of production and a return. These contracts expire December 2003 through June 2010. PNM's trading portfolio as of December 31, 2001 included open contract positions to buy $66.9 million of electricity and to sell $25.7 million of electricity. In addition, PNM had open contract positions classified as normal sales of electricity under the derivative accounting rules of $48.9 million and normal purchases of electricity of $8.1 million.

PNM has a coal supply contract for the needs of San Juan Generating Station ("SJGS") until 2017. The contract contemplates the delivery of approximately 103 million tons of coal during its remaining term. The pricing is based on the cost of extraction plus a margin.

The Company contracts for the purchase of gas to serve its jurisdictional customers. These contracts are short-term in nature supplying the gas needs for the current heating season and the following off-season months. The price of gas is a pass-through, whereby the Company recovers 100% of its cost of gas.

Contingent Provisions of Certain Obligations

The Company and PNM have a number of debt obligations and other contractual commitments that contain contingent provisions. Some of these, if triggered, could affect the liquidity of the Company. The Company and/or PNM could be required to provide security, immediately pay outstanding obligations or be prevented from drawing on unused capacity under certain credit agreements, if the contingent requirements were to be triggered. The most significant consequences resulting from these contingent requirements are detailed in the discussion below.

PNM's master purchase agreement for the procurement of gas for its jurisdictional customers contains a contingent requirement that could require PNM to provide security for its gas purchase obligations if the seller were to reasonably believe that PNM was unable to fulfill its payment obligations under the agreement.

The master agreement for the sale of electricity in the Western System Power Pool ("WSPP") contains a contingent requirement that could require PNM to provide security if its' debt were to fall below the investment grade rating. The WSPP agreement also contains a contingent requirement, commonly called a material adverse change ("MAC") provision, which could require PNM to provide security if a material adverse change in its financial condition or operations were to occur.

PNM's committed Credit Facility contains a MAC provision which if triggered could prevent PNM from drawing on its unused capacity under the Credit Facility. In addition, the Credit Facility contains a contingent requirement that requires PNM to maintain a debt-to-capital ratio of less than 70%. If PNM's debt-to-capital ratio were to exceed 70%, PNM could be required to repay all borrowings under the Credit Facility, be prevented from drawing on the unused capacity under the Credit Facility, and be required to provide security for all outstanding letters of credit issued under the Credit Facility. At December 31, 2001, the Company had $6.3 million of letters of credit outstanding.

If a contingent requirement were to be triggered under the Credit Facility resulting in an acceleration of the outstanding loans under the Credit Facility, a cross-default provision in the PVNGS leases could occur if the accelerated amount is not paid. If a cross-default provision is triggered, the lessors have the ability to accelerate their rights under the leases, including acceleration of all future lease payments.

Planned Financing Activities

PNM has $268.4 million of long-term debt that matures in August 2005. All other long-term debt matures in 2016 or later. The Company could enter into other long-term financings for the purpose of strengthening its balance sheet, funding growth and reducing its cost of capital. The Company continues to evaluate its investment and debt retirement options to optimize its financing strategy and earnings potential. No additional first mortgage bonds may be issued under PNM's mortgage. The amount of SUNs that may be issued is not limited by the SUNs indenture. However, debt-to-capital requirements in certain of PNM's financial instruments would ultimately limit the amount of SUNs PNM would issue.

PNM currently has $182.0 million of tax-exempt bonds outstanding that are callable at a premium in December 2002 and August 2003. PNM intends to refinance these bonds assuming the interest rate of the refinancing does not exceed the current interest rate and has hedged the entire planned refinancing. In order to take advantage of current low interest rates, PNM entered into two forward starting interest rate swaps in November and December 2001 and three additional contracts subsequent to December 31, 2001. PNM designated these swaps as cash flow hedges. The hedged risks associated with these instruments are the changes in cash flows related to general moves in interest rates expected for the refinancing. The swaps effectively cap the hedged interest rate on the refinancing to 4.9% plus an adjustment for the Company's and industry's credit rating. PNM assessment of hedge effectiveness is based on changes in the hedged interest rates. The derivative accounting rules, as amended, provide that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transactions affect earnings. Any hedge ineffectiveness is required to be presented in current earnings. There was no material hedge ineffectiveness in the year ended December 31, 2001.

A forward starting swap does not require any upfront premium and captures changes in the corporate credit component of an investment grade company's interest rate as well as the underlying Treasury benchmark. The five forward starting interest rate swaps have termination dates and notional amounts as follows: one with a termination date of September 17, 2002 for a notional amount of $46.0 million and four with a termination date of May 15, 2003 for a combined notional amount of $136.0 million. There were no fees on the transaction, as they are imbedded in the rates, and the transaction is cash settled on the mandatory unwind date (strike date), corresponding to the refinancing date of the underlying debt. The settlement will be capitalized as a cost of issuance and amortized over the life of the debt as a yield adjustment. If the hedged corporate interest rate along with the underlying benchmark were to decline below the capped level of the hedge, PNM will have to pay to settle the forward starting swap but would be able to issue the refinanced debt at the lower interest rate. However, if the hedged corporate interest rate along with the underlying benchmark were to decline but the interest rates available to PNM at the time of refinancing are greater than the existing rate of the debt to be refinanced due to credit issues, PNM will incur a loss on the hedge and not refinance the debt.

Stock Repurchase

In March 1999, PNM's Board of Directors approved a plan to repurchase up to 1,587,000 shares of its outstanding common stock with maximum purchase price of $19.00 per share. In December 1999, PNM's Board of Directors authorized PNM to repurchase up to an additional $20.0 million of its common stock. As of December 31, 1999, PNM repurchased 1,070,700 shares of its previously outstanding common stock at a cost of $18.8 million. From January 2000 through March 2000, PNM repurchased an additional 1,167,684 shares of its outstanding common stock at a cost of $18.8 million.

On August 8, 2000, PNM's Board of Directors approved a plan to repurchase up to $35.0 million of its outstanding common stock through the end of the first quarter of 2001. From August 8, 2000 through December 31, 2000, PNM repurchased an additional 417,900 shares of its outstanding common stock at a cost of $9.0 million. The total cost of stock repurchased for the year ended December 31, 2000 was $27.9 million. There were no repurchases of common stock during the year ended December 31, 2001. The Board of Directors has authorized additional stock repurchases but the Company has not exercised that new authority.

Dividends

The Company's Board of Directors reviews the Company's dividend policy on a continuing basis. The declaration of common dividends is dependent upon a number of factors including the ability of the Company's subsidiaries to pay dividends. Currently, PNM is the Company's primary source of dividends. As part of the order approving the formation of the holding company, the PRC placed certain restrictions on the ability of PNM to pay dividends to its parent.

The PRC order imposed the following conditions regarding dividends paid by PNM to the holding company: PNM can not pay dividends which cause its debt rating to go below investment grade; and PNM can not pay dividends in any year, as determined on a rolling four quarter basis, in excess of net earnings without prior PRC approval. Additionally, PNM has various financial covenants which limit the transfer of assets, through dividends or other means.

In addition, the ability of the Company to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of retained earnings, its financial circumstances and performance, the PRC's decisions in various regulatory cases currently pending and which may be docketed in the future, the effect of deregulating generation markets and market economic conditions generally. The ability to recover stranded costs in deregulation (as amended), conditions imposed on holding company formation, future growth plans and the related capital requirements and standard business considerations may also affect the Company's ability to pay dividends.

Consistent with the PRC's holding company order, PNM paid dividends of $127.0 million to the Company on December 31, 2001. On March 4, 2002, the PNM Board of Directors declared an additional dividend of approximately $5.5 million, which was paid March 19, 2002.

On February 19, 2002, the Company's Board of Directors approved a 10 percent increase in the common stock dividend. The increase raises the quarterly dividend to $0.22 per share, for an indicated annual dividend of $0.88 per share. The Company's Board of Directors approved a policy for future dividend increases in the range of 8 to 10 percent annually, targeting a payout of between 50 to 60 percent of regulated earnings. The Company believes that this target is consistent with the Company's expectation of future operating cash flows and the cash needs of its planned increase in generating capacity.

Capital Structure

The Company's capitalization, including current maturities of long-term debt, at December 31 is shown below:

	2001	2000
Common Equity	50.8%	48.6%
Preferred Stock	0.6	0.7
Long-term Debt	48.6	50.7
Total Capitalization*	100.0%	100.0%

*Total capitalization does not include as debt the present value of PNM's operating lease obligations for PVNGS Units 1 and 2, EIP and the Delta PPA which was $224 million as of December 31, 2001 and $227 million as of December 31, 2000.

OTHER ISSUES FACING THE COMPANY

RESTRUCTURING THE ELECTRIC UTILITY INDUSTRY

In April 1999, New Mexico's Electric Utility Industry Restructuring Act of 1999 (the "Restructuring Act") was enacted into law. The Restructuring Act opens the state's electric power market to customer choice. In March 2001, amendments to the Restructuring Act were passed which delay the original implementation dates by approximately five years, including the requirement for corporate separation of supply service and energy-related service assets from distribution and transmission service assets. In addition, the PRC will have the authority to delay implementation for another year under certain circumstances. The Restructuring Act, as amended, will give schools, residential and small business customers the opportunity to choose among competing power suppliers beginning in January 2007. Competition would be expanded to include all customers starting in July 2007. The Company is unable to predict the form of its further restructuring will take under the delayed implementation of customer choice. In addition, the Restructuring Act, as amended, recognizes that electric utilities should be permitted a reasonable opportunity to recover an appropriate amount of the costs previously incurred in providing electric service to their customers.

The amendments to the Restructuring Act required that the PRC approve a holding company, subject to terms and conditions in the public interest, without corporate separation of supply service and energy-related service assets from distribution and transmission service assets, by July 1, 2001. In addition, the amendments allow utilities to engage in unregulated power generation business activities until corporate separation is implemented.

On December 31, 2001, the Company implemented the holding company structure without corporate separation of supply service and energy-related services assets from distribution and transmission services assets. This structure provides for a holding company whose current holdings will be PNM, Avistar and other inactive unregulated subsidiaries. This was effected through the share exchange between PNM shareholders and the holding company, PNM Resources. Avistar and most of the inactive unregulated subsidiaries became wholly-owned subsidiaries of the holding company in January 2002. The transfer of certain corporate related assets to the holding company also occurred in January 2002. There are no current plans to provide the holding company with significant debt financing.

The 2002 session of the New Mexico Legislature resulted in enactment of tax measures favorable to the construction of merchant generating plants and plants fueled by renewable resources. The new laws provide authority for all local governments in the state to issue industrial revenue bonds for merchant generating plants smaller than 300 MW. The bonds provide exemptions from property taxes. Also enacted into law was a 5% investment tax credit for merchant generating plants smaller than 300 MW; tax credits for qualified generators using renewable resources; and an exemption from gross receipts tax for the cost of certain wind generation equipment.

There is a growing concern in New Mexico about the use of water for merchant power plants, due to the increased activity in building these plants in the state, which has an arid climate. The availability of sufficient water supplies to meet all the needs of the state, including growth, is a major issue. It is expected that the Legislature will appoint an interim committee to study the impact of power plants on the state's water and other natural resources, with a report to be issued for the 2003 session. In building the Afton and Lordsburg plants, which are much smaller than other merchant plants under construction or planned by other generating companies, the Company has secured sufficient water rights.

Congress is currently considering a number of bills affecting the energy industry, including comprehensive energy policy legislation that addresses numerous electricity issues that are fundamental to the structure of the industry. Among the provisions being considered are: granting FERC jurisdiction over currently non-jurisdictional entities for transmission; granting FERC authority to require participation in Regional Transmission Organizations ("RTO"); reliability standards; transmission pricing and siting; Public Utility Holding Company Act repeal; Public Utility Regulatory Policies Act repeal; net metering requirements; additional consumer protections; and renewable energy requirements. In addition, proposed tax legislation contains provisions relating to electric industry restructuring, primarily directing the Treasury Department, in consultation with FERC, to conduct a study of tax issues resulting from restructuring and to report to Congress annually. The tax legislation being considered also contains provisions regarding tax credits for electricity production from renewable resources, clean coal technologies and fuel cells, as well as tax incentives for energy conservation and efficiency measures. On March 8, 2002, the Senate passed the Economic Stimulus Package previously passed by the House of Representatives. The Package includes an extension to the federal production tax credit until January 1, 2004. The President is expected to sign the Package into law. The Company will continue to participate in the debate regarding national energy policy and any legislation affecting the industry.

In August 2001, the FERC issued a series of orders requiring existing independent system operators and developing RTOs in the Eastern United States to enter into mediation to form a single RTO in the Northeast and a second in the Southeast. The FERC expressed the desire that four RTO's be formed in the United States, two in the East, one in the Midwest and one in the West. The Company along with other Southwest transmission owners formed an RTO and made a filing on October 16, 2001 with the FERC.

The FERC has indicated its intention to initiate a separate Notice of Proposed Rulemaking that would require implementation of new Open Access Transmission Tariffs by RTOs and by public utilities that own, operate, or control interstate transmission facilities. The new tariffs would adopt provisions to implement new transmission services and a standardized wholesale market design. The new functions would be implemented by an independent entity, which could be an RTO, that would perform services under the standard market design under rules applicable to all transmission customers.

RECOVERY OF CERTAIN COSTS UNDER THE RESTRUCTURING ACT

Stranded Costs

The Restructuring Act, as amended, recognizes that electric utilities should be permitted a reasonable opportunity to recover an appropriate amount of the costs previously incurred in providing electric service to their customers. These stranded costs represent all costs associated with generation-related assets, currently in rates, in excess of the expected competitive market price over the life of those assets and include plant decommissioning costs, regulatory assets, and lease and lease-related costs. Utilities will be allowed to recover no less than 50% of stranded costs through a non-bypassable charge on all customer bills for five years after implementation of customer choice. The PRC could authorize a utility to recover up to 100% of its stranded costs if the PRC finds that recovery of more than 50%: (i) is in the public interest; (ii) is necessary to maintain the financial integrity of the public utility; (iii) is necessary to continue adequate and reliable service; and (iv) will not cause an increase in rates to residential or small business customers during the transition period. The Restructuring Act, as amended, also allows for the recovery of nuclear decommissioning costs by means of a separate wires charge over the life of the underlying generation assets (see Nuclear Regulatory Commission Prefunding below).

The calculation of stranded costs is subject to a number of highly sensitive assumptions, including the date of open access, appropriate discount rates and projected market prices, among others. The Restructuring Act, as amended, requires the Company to file a transition plan which includes provisions for the recovery of stranded costs and other expenses associated with the transition to a competitive market no later than January 1, 2005. The Company is unable to predict the amount of stranded costs that it may seek to recover at that time. The Company's previous proposal to recover its stranded costs under the original customer choice implementation dates would not accurately represent the Company's expected stranded costs under the amended implementation dates of the Restructuring Act.

Approximately $142 million of costs associated with the power supply and energy services businesses under the Restructuring Act were established as regulatory assets. Because of the Company's belief that recovery is probable, these assets continue to be classified as regulatory assets, although the Company has discontinued the use of accounting for rate regulated activities. The amendments to the Restructuring Act provide the opportunity for amortization of coal mine decommissioning costs currently estimated at approximately $100 million. The Company intends to seek recovery of these costs in its next rate case filing and believes that the costs are fully recoverable. The Company believes that any remaining portion of the regulatory assets will be fully recovered in future rates, including through a non-bypassable wires charge.

management's discussion and analysis of financial condition and results of operations

The Company believes that the Restructuring Act, as amended, if properly applied, provides an opportunity for recovery of a reasonable amount of stranded costs should such costs exist at the time of separation. If regulatory orders do not provide for a reasonable recovery, the Company is prepared to vigorously pursue judicial remedies. The PRC will make a determination and quantification of stranded cost recovery prior to implementation of restructuring. The determination may have an impact on the recoverability of the related assets and may have a material effect on the future financial results and position of the Company.

Transition Cost Recovery

In addition, the Restructuring Act, as amended, authorizes utilities to recover in full any prudent and reasonable costs incurred in implementing full open access ("transition costs"). These transition costs are currently scheduled to be recovered from 2007 through 2012 by means of a separate wires charge. The PRC may extend this date by up to one year. The Company may seek to recover transition costs already incurred in future rate cases that may occur prior to open access. The Company is unable to predict the amount of transition costs it may incur. To date, the Company has capitalized $24.3 million of expenditures that meet the Restructuring Act's definition of transition costs. Transition costs for which the Company will seek recovery include professional fees, financing costs, consents relating to the transfer of assets, management information system changes including billing system changes and public and customer education and communications. These costs will be amortized over the recovery period to match related revenues. The Company intends to vigorously pursue remedies available to it should the PRC disallow recovery of reasonable transition costs. Costs not recoverable will be expensed when incurred unless these costs are otherwise permitted to be capitalized under current and future accounting rules. Depending on the amount of non-recoverable transition costs, if any, the resulting charge to earnings may have a material effect on the future financial results and position of the Company.

Nuclear Regulatory Commission ("NRC") Prefunding

Pursuant to NRC rules on financial assurance requirements for the decommissioning of nuclear power plants, the Company has a program for funding its share of decommissioning costs for PVNGS through a sinking fund mechanism. The NRC rules on financial assurance became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated decommissioning costs through cost of service rates or a "non-bypassable charge". Other mechanisms are prescribed, such as prepayment, surety methods, insurance and other guarantees, to the extent that the requirements for exclusive reliance on the fund mechanism are not met.

The Restructuring Act, as amended, allows for the recoverability of 50% up to 100% of stranded costs including nuclear decommissioning costs. The results of the 1998 triannual decommissioning cost study indicated that PNM's share of the PVNGS decommissioning costs excluding spent fuel disposal will be approximately $181.0 million (in 1998 dollars). The Restructuring Act, as amended, specifically identifies nuclear decommissioning costs as eligible for separate recovery over a longer period of time than other stranded costs if the PRC determines a separate recovery mechanism to be in the public interest. In addition, the Restructuring Act, as amended, states that it does not require the PRC to issue any order which would result in loss of eligibility to exclusively use external sinking fund methods for decommissioning obligations pursuant to Federal regulations. When final determination of stranded cost recovery is made and if the Company is unable to meet the requirements of the NRC rules permitting the use of an external sinking fund because it is unable to recover all of its estimated decommissioning costs through a non-bypassable charge, the Company may have to pre-fund or find a similarly capital intensive means to meet the NRC rules. There can be no assurance that such an event will not negatively affect the funding of the Company's growth plans.

MERCHANT PLANT FILING

Senate Bill ("SB") 266, enacted by the 2001 session of the New Mexico legislature, allowed public utilities to "invest in, construct, acquire or operate" a generating plant not intended to provide retail electric service, free of certain otherwise applicable regulatory requirements contained in the Public Utility Act. By order entered on March 27, 2001, the PRC found that these provisions of SB 266 raised issues such as cost allocations for ratemaking, revenue allocations for off-system sales, how the Commission can ensure the utility will meet its duty to provide service when the utility invests in such generating plant, how that plant will be financed and how transactions between regulated services and merchant plants will be conducted. The Company has filed a pleading addressing these issues and testimony in response to interested parties' requests. The PRC has established a schedule for the filing of staff and intervenor testimony and for the Company's rebuttal testimony, culminating in a hearing scheduled for June 10, 2002.

In November 2001, the Company began settlement negotiations with the PRC's utility staff and intervenors related to these PRC proceedings in order to resolve a number of matters. In addition to the issues being examined in the Company's merchant plant filing, discussions have included the future framework for restructuring the electric industry in New Mexico under the Restructuring Act, and a future retail electric rate path. The negotiations include the potential implementation and effective date of rates that would replace those approved under the rate freeze stipulation that remains in effect until January 1, 2003.

The Company is currently unable to predict the impact these proceedings may have on its plans to expand its generating capacity and other operations.

WESTERN UNITED STATES WHOLESALE POWER MARKET

A significant portion of the Company's earnings in 2001 was derived from the Company's wholesale power trading operations, which benefited from strong demand and high wholesale prices in the Western United States. These market conditions were primarily driven by the electric power supply shortages in the Western United States during the first half of the year. As a result of the supply imbalance, the wholesale power market in the Western United States became extremely volatile and, while providing many marketing opportunities, presented and continues to present significant risk to companies selling power into this marketplace.

Moderate weather in California, as well as certain regulatory actions (see below), have caused a significant decline in the price of wholesale electricity in the Western United States wholesale power market. In addition, conservation measures and new generation have or are expected to put downward pressure on wholesale electricity prices. As a result of these trends, the Company expects its earnings from wholesale power trading operations to be significantly lower in the future than the levels seen during the last half of 2000 and the first half of 2001.

The power market in the Western United States has been the subject of widespread national attention. At the heart of the situation were flaws in the California deregulation legislation and a significant imbalance between electric supply and demand. These circumstances were aggravated by other factors such as increases in gas supply costs, weather conditions and transmission constraints. The FERC and the California Public Utilities Commission ("CPUC") have entered a series of orders addressing, respectively, the wholesale pricing of electricity into the California market and the retail pricing of electricity to California consumers. These initiatives put significant downward pressure on wholesale prices. The Company cannot predict the ultimate outcome of these governmental initiatives and their long-term effect on the Western United States power market or on the Company's ability to market into the California market.

During 2001, regional wholesale electricity prices reached over $1,000 per MWh mainly due to the electric power shortages in the West although current price levels are much depressed from this level. Two of California's major utilities, Southern California Edison Company ("SCE") and Pacific Gas and Electric Co. ("PG&E"), were unable to fully recover their wholesale power costs from their retail customers. As a result, both utilities experienced severe liquidity constraints. PG&E decided to seek bankruptcy protection while SCE was forced to consider bankruptcy.

In response to the turmoil in the California energy market, the FERC initially imposed a "soft"price cap of $150 per MWh for sales to the California Power Exchange ("Cal PX") and the California Independent System Operator ("Cal ISO") that required any wholesale sales of electricity into these markets be capped at $150 per MWh unless the seller could demonstrate that its costs exceeded the cap. This price cap was effectively modified by FERC orders issued in March and April 2001 that directed certain power suppliers to provide refunds for overcharges calculated on the basis of a formula that sanctioned wholesale prices considerably in excess of the $150 per MWh level. On April 26, 2001, the FERC adopted an order establishing prospective mitigation and a monitoring plan for the California wholesale markets and which established a further investigation of public utility rates in wholesale Western energy markets. The plan reflected in the April 26 order, replaced the $150 per MWh soft cap previously established and applied during periods of system emergency. Thereafter, on June 19, 2001, the FERC issued still another order that changed the previous orders and expanded the price mitigation approach of the April 26 order to all of the Western region. As a result of the price mitigation plan and other factors, such as moderate weather in California and lower gas prices, wholesale electric prices declined significantly by the end of the third quarter and remained low through the fourth quarter. The Company is unable to predict the impact the price mitigation plan will ultimately have on the wholesale market, but expects that if wholesale electric prices remain at current levels, future operating revenues from Generation and Trading will be significantly lower than in the first half of 2001.

The June 19 order also directed a FERC administrative law judge to convene a settlement conference to address potential refunds owed by sellers into the California market. The settlement conference, in which the Company participated, was ultimately unsuccessful, but the administrative law judge called in his recommendation to the FERC for an evidentiary hearing to resolve the dispute, suggesting that refunds were due; however, the estimated refunds were significantly lower than demanded by

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California, and in most instances, were offset by the amounts due suppliers from the Cal PX and Cal ISO. California had demanded refunds of approximately $9 billion from power suppliers. On July 25, 2001, acting on the recommendation of the administrative law judge, the FERC ordered an expedited fact-finding hearing to evaluate refunds for spot market transactions in California. The FERC also ordered a preliminary hearing to determine whether refunds were due resulting from wholesale sales into the Pacific Northwest. The Pacific Northwest matter was heard by an administrative law judge whose recommended decision declined to order refunds resulting from sales into the Pacific Northwest, but the FERC has not yet acted on this recommended decision. The hearing on potential California refund obligations has not yet been completed and a recommended decision is not anticipated until the second half of 2002. The Company is unable to predict the ultimate outcome of these FERC proceedings, or whether the Company will be directed to make any refunds as the result of a FERC order.

In 2001, approximately $2 million in wholesale power sales by the Company were made directly to the Cal PX, which was the main market for the purchase and sale of electricity in the state in the beginning of 2001, or the Cal ISO which manages the state's electricity transmission network. In January and February 2001, SCE and PG&E, major purchasers of power from the Cal PX and ISO, defaulted on payments due the Cal PX for power purchased from the Cal PX in 2000. These defaults caused the Cal PX to seek bankruptcy protection. The Company has filed its proofs of claims in the Cal PX and PG&E bankruptcy proceedings. Total amounts due from the Cal PX or Cal ISO for power sold to them in 2000 and 2001 total approximately $7 million. The Company has provided allowances for the total amount due from the Cal PX and Cal ISO.

Prior to its bankruptcy filing, the Cal PX undertook to charge back the defaults of SCE and PG&E to other market participants, in proportion to their participation in the markets. The Company was invoiced for $2.3 million as its proportionate share under the Cal PX tariff. The Company, as well as a number of power marketers and generators, filed complaints with the FERC to halt the Cal PX's attempt to collect these payments under the charge-back mechanism, claiming the mechanism was not intended for these purposes, and even if it was so intended, such an application was unreasonable and destabilizing to the California power market. The FERC has issued a ruling on these complaints eliminating the "charge-back"mechanism.

With the demise of the Cal PX in February 2001, the California Department of Water Resources ("Cal DWR") commenced a program of purchasing electric power needed to supply California utility customers serviced by PG&E and SCE as these utilities lacked the liquidity to purchase supplies. The purchases were financed by legislative appropriation, with the expectation that this funding would be replaced with the issuance of revenue bonds by the state. In the first quarter of 2001, the Company began to sell power to the Cal DWR. The Company has regularly monitored its credit risk with regard to its Cal DWR sales and believes its exposure is prudent.

In addition to sales directly to California, the Company sells power to customers in other jurisdictions who sell to California and whose ability to pay the Company may be dependent on payment from California. The Company is unable to determine whether its non-California power sales ultimately are resold in the California market. The Company's credit risk is monitored by its Risk Management Committee, which is comprised of senior finance and operations managers. The Company seeks to minimize its exposure through established credit limits, a diversified customer base and the structuring of transactions to take advantage of off-setting positions with its customers. To the extent these customers who sell power into California are dependent on payment from California to make their payments to the Company, the Company may be exposed to credit risk which did not exist prior to the California situation.

In 2001, in response to the increased credit risk and market price volatility described above, the Company provided an additional allowance against revenue of $3.5 million for anticipated losses to reflect management's estimate of the increased market and credit risk in the wholesale power market and its impact on 2001 revenues. Based on information available at December 31, 2001, the Company believes the total allowance for anticipated losses, currently established at $12.0 million, is adequate for management's estimate of potential uncollectible accounts. The Company will continue to monitor the wholesale power marketplace and adjust its estimates accordingly.

The CPUC has commenced an investigation into the functioning of the California wholesale power market and its associated impact on retail rates. The Company, along with other power suppliers in California, has been served with a subpoena in connection with this investigation and has responded to the subpoena. The Company has been advised that the California Attorney General is conducting an investigation into possibly unlawful, unfair or anti-competitive behavior affecting electricity rates in California, and that Company documents will be subpoenaed in the future in connection with this investigation. The California Attorney General has filed a lawsuit against certain power marketers for alleged unfair trade practices involving the reselling of reserved capacity. The Company is not one of the named defendants. Other related investigations have been commenced by other federal and state governmental bodies.

In addition, there are several class action lawsuits that have been filed in California against generators and wholesale sellers of energy into the California market. These actions allege, in essence, that the defendants engaged in unlawful and unfair business practices to manipulate the wholesale energy market, fix prices and restrain supply, and thereby drive up prices. The Company is not a named defendant in any of these actions.

The Company does not believe that these matters will have a material adverse effect on its results of operations or financial position.

As noted above, SCE has been forced to consider a bankruptcy filing. However, at the present time such a bankruptcy filing does not appear likely, given the understanding that SCE has refinanced a significant portion of its outstanding debt and cured many previously existing payment defaults under its debt agreements and also with the Cal PX and other suppliers. SCE is a 15.8% participant in PVNGS and a 48.0% participant in Four Corners. Pursuant to an agreement among the participants in PVNGS and an agreement among the participants in Four Corners Units 4 and 5, each participant is required to fund its proportionate share of operation and maintenance, capital, and fuel costs of PVNGS and Four Corners Units 4 and 5. The Company estimates SCE's total monthly share of these costs to be approximately $7.8 million for PVNGS and $8.0 million for Four Corners. The agreements provide that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant for a period of six months. During this time the defaulting participant is entitled to its share of the power generated by the respective station. After this grace period, the defaulting participant must make its payments in arrears before it is entitled to its continuing share of power. SCE has not defaulted on its payment obligations with respect to PVNGS and Four Corners.

TERMINATION OF WESTERN RESOURCES TRANSACTION

On November 9, 2000, PNM and Western Resources announced that both companies' Boards of Directors approved an agreement under which PNM would acquire the Western Resources electric utility operations in a tax-free, stock-for-stock transaction. The agreement required that Western Resources split-off its non-utility businesses to its shareholders prior to closing.

In July 2001, the KCC issued two orders. The first order declared the split-off required by the agreement to be unlawful as designed, with or without a merger. The second order decreased rates for Western Resources, despite a request for a $151 million increase. After rehearing the KCC established the rate decrease at $15.7 million. On October 3, 2001, the KCC issued an Order on Reconsideration reaffirming its decision that the split-off as designed in the agreement was unlawful with or without a merger.

Because of these rulings, the Company announced that it believed the agreement as originally structured could not be consummated. Efforts to renegotiate the transaction failed. Western Resources demanded that the Company file for regulatory approvals of the transaction as designed, despite the fact that the transaction required the split-off already determined to be unlawful by the KCC. As a result of the disagreement over the viability of the transaction as designed, the Company filed suit on October 12, 2001, in New York state court seeking declarations that the transaction could not be accomplished as designed due to the KCC's determination that the split-off condition of the transaction is unlawful; that the Company is not obligated to pursue approvals of the transaction as designed; that the transaction is terminated effective December 31, 2001, without an automatic extension; and that the KCC rate case order constitutes a material adverse effect under the agreement. The Company also seeks monetary damages for breach of contract because Western Resources represented and warranted that the split-off did not require approval of the KCC.

On November 19, 2001, Western Resources filed a complaint against the Company in New York state court alleging breach of contract and breach of implied covenant of good faith and fair dealing. Western Resources alleged that the Company brought about the KCC orders, failed to assist in efforts to reverse the KCC orders, refused to renegotiate within the terms of the agreement, interfered with Western Resources' efforts to satisfy the terms of the agreement, and effected an unauthorized de facto termination of the agreement by filing its complaint. Western Resources alleges damages in excess of $650 million. The Company believes that the complaint filed by Western Resources is without merit and intends to vigorously defend itself against the complaint. The Company also intends to vigorously pursue its own complaint.

On January 7, 2002, the Company notified Western Resources that it had taken action to terminate the agreement as of that date. The Company identified numerous breaches of the agreement by Western Resources and the regulatory rulings in Kansas as reasons for the termination. On January 9, 2002, Western Resources responded that it considered the Company's termination to be ineffective and the agreement to still be in effect.

On February 5, 2002, the District Court for Shawnee County, Kansas, dismissed without prejudice Western Resources' petition for judicial review of the KCC's split-off orders. The Court ruled that by filing a new financial plan in compliance with the orders, Western Resources accepted certain portions of the orders thereby creating a situation where further administrative action became necessary. As a result, the Court concluded that the matter was not ripe for judicial review and remanded the case to the KCC.

On March 8, 2002, the Kansas Court of Appeals affirmed the KCC's rate order.

The Company is currently unable to predict the outcome of its litigation with Western Resources.

IMPLEMENTATION OF NEW CUSTOMER BILLING SYSTEM

On November 30, 1998, the Company implemented a new customer billing system. Due to a significant number of problems associated with the implementation of the new billing system, the Company was unable to generate appropriate bills for all its customers through the first quarter of 1999 and was unable to analyze delinquent accounts until November 1999. As a result of the delay of normal collection activities, the Company incurred a significant increase in delinquent accounts, many of which occurred with customers that no longer have active accounts with the Company. As a result, the Company significantly increased its estimated bad debt costs throughout 1999 and 2000.

The Company continued its analysis and collection efforts of its delinquent accounts resulting from the problems associated with the implementation of the new customer billing system throughout 2000 and identified additional bad debt exposure. By the end of 2000, the Company completed its analysis of its delinquent accounts and resumed its normal collection procedures. Based upon information available at December 31, 2001, the Company believes the allowance for doubtful accounts of $7.7 million is adequate for management's estimate of potential uncollectible accounts.

The following is a summary of the allowance for doubtful accounts for the Utility Operations which utilizes the customer billing system during 2001, 2000 and 1999:

	2001	2000	1999
		(In thousands)	
Allowance for doubtful accounts, beginning of year	$ 7,550	$12,504	$ 836
Bad debt expense	5,682	8,567	11,496
Less: Write off (adjustments) of uncollectible accounts	5,566	13,521	(172)
Allowance for doubtful accounts, end of year	$ 7,666	$ 7,550	$12,504

Note: Above schedule excludes bad debt allowance for the Generation and Trading Operations

EFFECTS OF CERTAIN EVENTS ON FUTURE REVENUES

The Company's 100 MW power sale contract with San Diego Gas and Electric Company ("SDG&E") expired on April 30, 2001 following FERC's acceptance for filing of a cancellation notice filed by the Company. The Company expects to replace these revenues, based on current market conditions. In addition, previously reported litigation between the Company and SDG&E regarding prior years' contract pricing has been resolved in the Company's favor.

On October 1, 1999, Western Area Power Administration ("WAPA") filed a petition at the FERC requesting the FERC, on an expedited basis, to order the Company to provide network transmission service to WAPA under the Company's Open Access Transmission Tariff on behalf of the United States Department of Energy ("DOE") as contracting agent for Kirtland Air Force Base ("KAFB").

In 2001, FERC issued a "proposed" order directing the Company to provide transmission service, but left the terms of service to be negotiated by the parties and subject to final FERC review and determination. In January 2002, the parties submitted a settlement agreement resolving most of the issues relating to the rates, terms and conditions of service. The "proposed" FERC order is not subject to requests for rehearing or judicial review. An order establishing terms and conditions (including compensation for transmission service) would be a "final" order that would be subject to requests for rehearing and to judicial review. The Company is evaluating its legal options in relation to the "proposed" order or any resulting "final" order. The settlement agreement reserves the Company's rights to seek rehearing and judicial review of any final order and to present other legal claims. In February 2002, the FERC administrative law judge who supervised the negotiations leading to the partial settlement recommended that FERC issue a final order approving the agreement. A related PRC proceeding has been stayed, pending the outcome of the FERC case.

The effect of the FERC's proposed order to provide transmission service, instead of the current retail sale that the Company makes to DOE on behalf of KAFB, depends upon the final terms of any FERC order as well as the Company's ability to sell the power to a different customer and the price that the Company would obtain if it makes such a sale. The Company believes that the impact will be immaterial based on the facts above.

COAL FUEL SUPPLY

In 1996, the Company was notified by San Juan Coal Company ("SJCC") that the Navajo Nation proposed to select certain properties within the San Juan and La Plata Mines (the "mining properties") pursuant to the Navajo-Hopi Land Settlement Act of 1974 (the "Act"). The mining properties are operated by SJCC under leases from the BLM and comprise a portion of the fuel supply for the SJGS. On November 6, 2001, an administrative order was issued denying the proposed selections. The Company is monitoring an appeal by the Navajo Nation and other developments on this issue and will continue to assess, but cannot estimate with any certainty the potential impacts to the SJGS and the Company's operations.

NEW SOURCE REVIEW RULES

The United States Environmental Protection Agency ("EPA") has proposed changes to its New Source Review ("NSR") rules that could result in many actions at power plants that have previously been considered routine repair and maintenance activities (and hence not subject to the application of NSR requirements) as now being subject to NSR. In November 1999, the Department of Justice at the request of the EPA filed complaints against seven companies alleging the companies over the past 25 years had made modifications to their plants in violation of the NSR requirements, and in some cases the New Source Performance Standards ("NSPS") regulations. Whether or not the EPA will prevail is unclear at this time. The EPA has reached a settlement with one of the companies sued by the Justice Department. Discovery continues in the pending litigation. No complaint has been filed against the Company, and the Company believes that all of the routine maintenance, repair, and replacement work undertaken at its power plants was and continues to be in accordance with the requirements of NSR and NSPS. However, by letter dated October 23, 2000, the New Mexico Environment Department ("NMED") made an information request of the Company, advising the Company that the NMED was in the process of assisting the EPA in the EPA's nationwide effort "of verifying that changes made at the country's utilities have not inadvertently triggered a modification under the Clean Air Act's Prevention of Significant Determination ("PSD") policies."The Company has responded to the NMED information request.

The nature and cost of the impacts of EPA's changed interpretation of the application of the NSR and NSPS, together with proposed changes to these regulations, may be significant to the power production industry. However, the Company cannot quantify these impacts with regard to its power plants. It is also not yet known what changes in EPA policy, if any, may occur in the NSR area as a result of the change in administration in Washington. The National Energy Policy released May 2001 by the National Energy Policy Development Group, called for a review of the pending NSR enforcement actions and that review continues by the EPA. If the EPA should prevail with its current interpretation of the NSR and NSPS rules, the Company may be required to make significant capital expenditures which could have a material adverse effect on the Company's financial position and results of operations.

THREATENED CITIZEN SUIT UNDER THE CLEAN AIR ACT

By letter dated January 9, 2002, counsel for the Grand Canyon Trust and Sierra Club (collectively, "GCT") notified the Company of GCT's intent to file a so-called "citizen suit" under the Clean Air Act ("Clean Air"), alleging that the Company and co-owners of the SJGS violated the Clean Air Act, and the implementing federal and state regulations, at SJGS. The notice indicates that penalties and injunctive relief may be sought. Under the Clean Air Act, GCT must wait at least 60 days after affording the Company notice (i.e., until March 9, 2002) before filing a lawsuit. The allegations contained in GCT's notice of intent to sue fall into three categories. First, GCT contends that the plant has violated, and is currently in violation, of the federal NSPS at all four units at SJGS. Second, GCT argues that the plant has violated, and is currently in violation, of the federal PSD rules, as well as the corresponding provisions of the New Mexico Administrative Code, at all four units. Third, GCT alleges that the plant has "regularly violated" the 20% opacity limit contained in SJGS's operating permit and set forth in federal and state regulations at Units 1, 3 and 4. The Company is currently investigating the allegations contained in the notice of intent to sue. Based on its investigation to date, the Company believes firmly that the allegations are without merit. By letter to GCT's counsel dated February 22, 2002, the Company vigorously disputed the allegations and affirmed its compliance with the laws in question. The Company adheres to high environmental standards as evidenced by its International Standards Organization ratings. In that letter, the Company also stated that the GCT has failed to provide sufficient information to permit full examination of the allegations. If a lawsuit is filed by GCT, as threatened, the Company will respond on behalf of the co-owners and vigorously defend in the litigation. The Company is, however, unable to predict the ultimate outcome of the matter.

NATURAL GAS EXPLOSION

On April 25, 2001, a natural gas explosion occurred in Santa Fe, New Mexico. The apparent cause of the explosion was a leak from a Company line near the location. The explosion destroyed a small building and injured two persons who were working in the building. The Company's investigation indicates that the leak was an isolated incident likely caused by a combination of corrosion and increased pressure. The Company also is cooperating with an investigation of the incident by the PRC's Pipeline Safety Bureau which issued its report on March 18, 2002. The Bureau's report gives PNM notice of 13 possible violations of the New Mexico Pipeline Safety Act and related regulations. Two lawsuits against the Company by the injured persons along with several claims for property and business interruption damages have been resolved by the Company. At this time, the Company is unable to estimate the potential liability, if any, that the Company may incur as a result of the Pipeline Safety Bureau's investigation. There can be no assurance that the outcome of this matter will not have a material impact on the results of operations and financial position of the Company.

NAVAJO NATION TAX ISSUES

Arizona Public Service Company ("APS"), the operating agent for Four Corners, has informed the Company that in March 1999, APS initiated discussions with the Navajo Nation regarding various tax issues in conjunction with the expiration of a tax waiver, in July 2001, which was granted by the Navajo Nation in 1985. The tax waiver pertains to the possessory interest tax and the business activity tax associated with the Four Corners operations on the reservation. The Company believes that the resolution of these tax issues will require an extended process and could potentially affect the cost of conducting business activities on the reservation. The Company is unable to predict the ultimate outcome of discussions with the Navajo Nation regarding these tax issues and cannot estimate with any certainty the potential impact on the Company's operations.

LANDOWNER ENVIRONMENTAL CLAIMS

Certain landowners owning property in the vicinity of the San Juan Generating Station have given notice to the Company of their intent to file suit against the Company and the other owners of the generating station. The asserted bases for the threatened litigation encompass a broad spectrum of allegations, including improper discharge of wastes and failure to remediate such discharges, poisoning of drinking waters, wrongful death and injury to persons, harm to landowner property, negligence, unnatural climate change, destruction of documents, racial discrimination, hostile work environment for employees at the plant and wrongful discharge of certain employees. The Company is in the process of reviewing these allegations and to date no suit has been filed. The Company has been informed that similar allegations have been made by the same landowners against Arizona Public Service Company, as operator of the Four Corners Power Plant, of which the Company is a co-owner.

NEW AND PROPOSED ACCOUNTING STANDARDS

Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 143. The statement requires the recognition of a liability for legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction or development and/or the normal operation of a long-lived asset. The asset retirement obligation is required to be recognized at its fair value when incurred. The cost of the asset retirement obligation is required to be capitalized by increasing the carrying amount of the related long-lived asset by the same amount as the liability. This cost must be expensed using a systematic and rational method over the related asset's useful life. SFAS 143 is effective for the Company beginning January 1, 2003. The Company is currently assessing the impact of SFAS 143 and is unable to predict its impact on the Company's operating results and financial position at this time.

Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* ("SFAS 144"). In August 2001, the FASB issued SFAS 144. The statement retains the requirements of the previously issued pronouncement on asset impairment, Statement of Financial Accounting Standards No. 121 ("SFAS 121"); however the SFAS 144 removes goodwill from the scope of SFAS 121, provides for a probability-weighted cash flow estimation approach for estimating possible future cash flows, and establishes a "primary asset" approach for a group of assets and liabilities that represents the unit of accounting to be evaluated for impairment. In addition, SFAS 144 changes the measurement of long-lived assets to be disposed of by sale, as accounted for by Accounting Principles Board Opinion No. 30. Under SFAS 144, discontinued operations are no longer measured on a net realizable value basis, and their future operating losses are no longer recognized before they occur. The Company does not believe SFAS 144 will have a material effect on its future operating results or financial position.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

Statements made in this annual report that relate to future events are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and are subject to risk and uncertainties. The Company assumes no obligation to update this information.

Because actual results may differ materially from expectations, the Company cautions readers not to place undue reliance on these statements. A number of factors, including weather, fuel costs, changes in the local and national economy, changes in supply and demand in the market for electric power, the outcome of litigation relating to the Company's terminated transaction with Western Resources, the performance of generating units and transmission system, and state and federal regulatory and legislative decisions and actions, including the wholesale electric power pricing mitigation plan ordered by FERC on June 18, 2001, rulings issued by the PRC pursuant to the Electric Utility Industry Restructuring Act of 1999, as amended, and in other cases now pending or which may be brought before the FERC and the PRC and any action by the New Mexico Legislature to further amend or repeal that Act, or other actions relating to restructuring or stranded cost recovery, or federal or state regulatory, legislative or legal action connected with the California wholesale power market and wholesale power markets in the West, could cause the Company's results or outcomes to differ materially from those indicated by such forward-looking statements in this filing.

QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electric prices, changes in interest rates and, historically, adverse market changes for investments held by the Company's various trusts. The Company also uses certain derivative instruments for bulk power electricity trading purposes in order to take advantage of favorable price movements and market timing activities in the wholesale power markets. Information about the Company's financial instruments is set forth in "Critical Accounting Policies" section of Management's Discussion of Results of Operations and Financial Condition and the Financial Instruments note in the to the Notes to the Consolidated Financial Statements and incorporated by reference. The following additional information is provided.

Risk Management

The Company controls the scope of its various forms of risk through a comprehensive set of policies and procedures and oversight by senior level management and the Board of Directors. The Company's Finance Committee of the Board of Directors sets the risk limit parameters. An internal risk management committee ("RMC"), comprised of corporate and business segment officers, oversees all of the activities, which include commodity price, credit, equity, interest rate and business risks. The RMC has oversight for the ongoing evaluation of the adequacy of the risk control organization and policies. The Company has a risk control organization, headed by the Director of Financial Risk Management ("Risk Manager"), which is assigned responsibility for establishing and enforcing the policies, procedures and limits and evaluating the risks inherent in proposed transactions, on an enterprise-wide basis.

The RMC's responsibilities specifically include: establishment of a general policy regarding risk exposure levels and activities in each of the business units; recommendation of the types of instruments permitted for trading; authority to establish a general policy regarding counterparty exposure and limits; authorization and delegation of trading transaction limits for trading activities; review and approval of controls and procedures for the trading activities; review and approval of models and assumptions used to calculate mark-to-market and risk exposure; authority to approve and open brokerage and counterparty accounts for derivative trading; review for trading and risk activities; and quarterly reporting to the Finance Committee and the Board of Directors on these activities.

The RMC also proposes Value at Risk ("VAR") limits to the Finance Committee. The Finance Committee ultimately sets the aggregate VAR limit.

It is the responsibility of each business unit to create its own control and procedures policy for trading within the parameters established by the Finance Committee. The RMC reviews and approves these policies, which are created with the assistance of the Chief Accounting Officer, Director of Internal Audit and the Risk Manager. Each business units' policies address the following controls: authorized risk exposure limits; authorized trading instruments and markets; authorized traders; policies on segregation of duties; policies on marking to market; responsibilities for trade capture; confirmation procedures; responsibilities for reporting results; statement on the role of derivatives trading; and limits on individual transaction size (nominal value) for traders.

To the extent an open position exists, fluctuating commodity prices can impact financial results and financial position, either favorably or unfavorably. As a result, the Company cannot predict with precision the impact that its risk management decisions may have on its businesses, operating results or financial position.

Commodity Risk

Trading and marketing operations often involve market risks associated with managing energy commodities and establishing open positions in the energy markets, primarily on a short-term basis. These risks fall into three different categories: price and volume volatility, credit risk of trading counterparties and adequacy of the control environment for trading. The company routinely enters into forward contracts and options to hedge purchase and sale commitments, fuel requirements and to minimize the risk of market fluctuations on the Generation and Trading Operations.

The Company's wholesale power marketing operations, including both firm commitments and trading activities, are managed through an asset backed strategy, whereby the Company's aggregate net open position is covered by its own excess generation capabilities. The Company is exposed to market risk if its generation capabilities were disrupted or if its jurisdictional load requirements were greater than anticipated. If the Company were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases.

The Company assesses the risk of these derivatives using the VAR method, in order to maintain the Company's total exposure within management-prescribed limits. The Company utilizes the variance/covariance model of VAR, which is a probabilistic model that measures the risk of loss to earnings in market sensitive instruments. The variance/covariance model relies on statistical relationships to analyze how changes in different markets can affect a portfolio of instruments with different characteristics and market exposure. VAR models are relatively sophisticated; however, the quantitative risk information is limited by the parameters established in creating the model. The instruments being evaluated may trigger a potential loss in excess of calculated amounts if changes in commodity prices exceed the confidence level of the model used. The VAR methodology employs the following critical parameters: volatility estimates, market values of open positions, appropriate market-oriented holding periods and seasonally adjusted correlation estimates. The Company uses a holding period of three days as the estimate of the length of time that will be needed to liquidate the positions. The volatility and the correlation estimates measure the impact of adverse price movements both at an individual position level as well as at the total portfolio level. The confidence level established is 99%. For example, if VAR is calculated at $10 million, it is estimated at a 99% confidence level that if prices move against the Company's positions, the Company's pre-tax gain or loss in liquidating the portfolio would not exceed $10 million in the three days that it would take to liquidate the portfolio.

The Company accounts for the sale of its electric generation in excess of its jurisdictional needs or the purchase of jurisdictional needs as non-trading. Non-jurisdictional purchases for resale and subsequent resales are accounted for as energy trading contracts. With respect to the Company's trading portfolio, the VAR was $1.2 million. The Company calculates a portfolio VAR which in addition to its trading portfolio includes all non-trading designated contracts, its generation assets excluded from jurisdictional rates and any excess jurisdictional capacity. This excess is determined using average peak forecasts for the respective block of power in the forward market. The Company's portfolio VAR was $12.4 million at December 31, 2001.

The Company's VAR is regularly monitored by the Company's RMC. The RMC has put in place procedures to ensure that increases in VAR are reviewed and, if deemed necessary, acted upon to reduce exposures. The VAR represents an estimate of the potential gains or losses that could be recognized on the Company's wholesale power marketing portfolio given current volatility in the market, and is not necessarily indicative of actual results that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ due to actual fluctuations in market rates, operating exposures, and the timing thereof, as well as changes to the Company's wholesale power marketing portfolio during the year.

In addition, the Company is exposed to credit losses in the event of non-performance or non-payment by counterparties. The Company uses a credit management process to access and monitor the financial conditions of counterparties. Credit exposure is also regularly monitored by the RMC. The Company provides for losses due to market and credit risk. The Company's credit risk with its largest counterparty as of December 31, 2001 and 2000 was $7.5 million and $16.7 million respectively.

The Company hedges certain portions of natural gas supply contracts in order to protect its jurisdictional customers from adverse price fluctuations in the natural gas market. The financial impact of all hedge gains and losses, including the related costs of the program, is recoverable through the Company's purchased gas adjustment clause as deemed prudently incurred by the PRC. As a result, earnings are not affected by gains and losses generated by these instruments.

Interest Rate Risk

As of December 31, 2001, the Company has an investment portfolio of fixed-rate government obligations and corporate securities which is subject to the risk of loss associated with movements in market interest rates. For accounting purposes, the portfolio is classified as available-for-sale and is marked-to-market. As a result, unrealized losses resulting from interest rate increases are recorded as a component of comprehensive income. If interest rates were to rise, 50 basis points from their levels at December 31, 2001, the fair value of these instruments would decline by 0.6% or $0.9 million. In addition, because of this interest rate sensitivity, early or unplanned redemption of these investments in a period of increasing interest rates would subject the Company to risk of a realized loss of principal as the fair market value of these investments would be less than their carrying value. The Company employs investment managers to mitigate this risk. As part of its investing strategies, the Company has diversified its portfolio with investments of varying maturity, obligors and limits credit exposure to high investment grade quality investments.

The Company has long-term debt which subjects it to the risk of loss associated with movements in market interest rates. All of the Company's long-term debt is fixed-rate debt, and therefore, does not expose the Company's earnings to a risk of loss due to adverse changes in market interest rates. However, the fair value of these debts instruments would increase by approximately 1.8% or $17.6 million if interest rates were to decline by 50 basis points from their levels at December 31, 2001. As of December 31, 2001, the fair value of the Company's long-term debt was $974 million as compared to a book-value of $954 million. In general, an increase in fair value would impact earnings and cash flows if the Company were to re-acquire all or a portion of its debt instruments in the open market prior to their maturity. Certain issuances of the Company's debt have call dates in December 2002 and August 2003. To hedge against the risk of rising interest rates and their impact on the economies of calling the debt, the Company has entered into two forward starting swaps in 2001 and three additional contracts in 2002. These forward interest rate swaps effectively lock-in interest rates for the notional amount of the debt that is callable at a rate of approximately 4.9% plus an adjustment for the Company's and Industry's credit rating. At December 31, 2001, the fair market value of these derivative financial instruments was approximately $2.0 million.

The Company contributed $6.1 million in 2001 to a trust established to fund decommissioning costs for PVNGS. In January 2002, the Company contributed $23.5 million for plan year 2001 to the trust for the Company's pension plan, and other postretirement benefits. The securities held by the trusts had an estimated fair value of $461.5 million as of December 31, 2001, of which approximately 30% were fixed-rate debt securities that subject the Company to risk of loss of fair value with movements in market interest rates. If rates were to increase by 50 basis points from their levels at December 31, 2001, the decrease in the fair value of the securities would be 3.0% or $4.0 million. The Company does not currently recover or return in jurisdictional rates losses or gains on these securities; therefore, the Company is at risk for shortfalls in its funding of its obligations due to investment losses. However, the Company does not believe that long-term market returns over the period of funding will be less than required for the Company to meet its obligations.

Equity Market Risk

As discussed above under Interest Rate Risk, the Company contributes to trusts established to fund its share of the decommissioning costs of PVNGS and other post retirement benefits. The trust holds certain equity securities as of December 31, 2001. These equity securities also expose the Company to losses in fair value. Approximately 60% of the securities held by the various trusts were equity securities as of December 31, 2001. Similar to the debt securities held for funding decommissioning and certain pension and other postretirement costs, the Company does not recover or return in jurisdictional rates losses or gains on these equity securities.

In 2001, the Company implemented an enhanced cash management strategy using derivative instruments based on the Standard & Poors 100 and 500 indices. The strategy is designed to capitalize on high market volatility or benefit from market direction. An investment manager is utilized to execute the program. The program is carefully managed by the RMC and limited to a one-day VAR of $5 million and a loss limit of $7.5 million. Trades are closed-out before the end of a reporting period and typically within the same day of execution. Recently, the RMC recommended and the Finance Committee approved the use of derivatives based on the Nasdaq composite index.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying financial statements, which consolidate the accounts of PNM Resources, Inc. and its subsidiaries, have been prepared in conformity with accounting principles generally accepted in the United States.

The integrity and objectivity of data in these financial statements and accompanying notes, including estimates and judgments related to matters not concluded by year-end, are the responsibility of management as is all other information in this Annual Report. Management devotes ongoing attention to review and appraisal of its system of internal controls. This system is designed to provide reasonable assurance, at an appropriate cost, that the Company's assets are protected, that transactions and events are recorded properly and that financial reports are reliable. The system is augmented by a staff of corporate auditors; careful attention to selection and development of qualified financial personnel; and programs to further timely communication and monitoring of policies, standards and delegated authorities.

The Audit Committee of the Board of Directors, composed entirely of outside directors, meets regularly with financial management, the corporate auditors and the independent auditors to review the work of each. The independent auditors and corporate auditors have free access to the Audit Committee, without management representatives present, to discuss the results of their audits and their comments on the adequacy of internal controls and the quality of financial reporting.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of PNM Resources, Inc.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of PNM Resources, Inc. (a New Mexico Corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of earnings, cash flows and comprehensive income for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the United States. 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 financial position of PNM Resources, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Albuquerque, New Mexico
February 1, 2002

pnm resources, inc. and subsidiaries
consolidated statements of earnings

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Operating Revenues:	*(In thousands, except per share amounts)*		
Electric	$1,965,142	$1,289,192	$ 911,977
Gas	385,418	319,924	236,711
Unregulated businesses	1,538	2,158	8,855
Total operating revenues	2,352,098	1,611,274	1,157,543
Operating Expenses:			
Cost of energy sold	1,536,566	949,880	531,952
Administrative and general	155,392	147,268	153,709
Energy production costs	152,455	139,894	140,784
Depreciation and amortization	96,936	93,059	92,661
Transmission and distribution costs	69,001	60,330	59,264
Taxes, other than income taxes	30,302	34,405	34,084
Income taxes	88,769	53,964	25,010
Total operating expenses	2,129,421	1,478,800	1,037,464
Operating income	222,677	132,474	120,079
Other Income and Deductions:			
Other	(15,110)	54,296	47,500
Income tax expense	7,706	(20,382)	(17,298)
Net other income and deductions	(7,404)	33,914	30,202
Income before interest charges	215,273	166,388	150,281
Interest Charges:			
Interest on long-term debt	62,716	62,823	65,899
Other interest charges	2,124	2,619	4,768
Net interest charges	64,840	65,442	70,667
Net Earnings from Continuing Operations	150,433	100,946	79,614
Cumulative Effect of a Change in Accounting Principle, Net of Tax	-	-	3,541
Net Earnings	150,433	100,946	83,155
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 149,847	$ 100,360	$ 82,569
Net Earnings per Share of Common Stock (Basic)	$ 3.83	$ 2.54	$ 2.01
Net Earnings per Share of Common Stock (Diluted)	$ 3.77	$ 2.53	$ 2.01
Dividends Paid per Share of Common Stock	$ 0.80	$ 0.80	$ 0.80

The accompanying notes are an integral part of these financial statements.

pnm resources, inc. and subsidiaries
consolidated balance sheets
assets

	YEAR ENDED DECEMBER 31, 2001	2000
Utility Plant, at original cost except PVNGS:	*(In thousands)*	
Electric plant in service	$2,118,417	$2,030,813
Gas plant in service	575,350	553,755
Common plant in service and plant held for future use	45,223	36,678
	2,738,990	2,621,246
Less accumulated depreciation and amortization	1,234,629	1,153,377
	1,504,361	1,467,869
Construction work in progress	249,656	123,653
Nuclear fuel, net of accumulated amortization of $16,954 and $19,081	26,940	25,784
Net utility plant	1,780,957	1,617,306
Other Property and Investments:		
Other investments	552,453	479,821
Non-utility property, net of accumulated depreciation of $1,580 and $1,644	1,784	3,666
Total other property and investments	554,237	483,487
Current Assets:		
Cash and cash equivalents	26,057	107,691
Accounts receivables, net of allowances of $18,025 and $13,279	147,787	238,426
Other receivables	52,158	64,857
Inventories	36,483	36,091
Regulatory assets	10,473	47,604
Short-term investments	45,111	-
Other current assets	31,428	11,417
Total current assets	349,497	506,086
Deferred charges:		
Regulatory assets	197,948	228,255
Prepaid pension cost	18,273	18,116
Other deferred charges	33,726	36,667
Total deferred charges	249,947	283,038
	$2,934,638	$2,889,917

The accompanying notes are an integral part of these financial statements.

consolidated balance sheets
capitalization and liabilities

	YEAR ENDED DECEMBER 31,	
	2001	2000
Capitalization:	*(In thousands)*	
Common stock equity:		
Common stock outstanding - 39,118 shares, no par value	$ 625,632	$ 627,811
Accumulated other comprehensive income, net of tax	(28,996)	(27)
Retained earnings	415,388	296,843
Total common stock equity	1,012,024	924,627
Minority interest	11,652	12,211
Cumulative preferred stock without mandatory redemption requirements	12,800	12,800
Long-term debt, less current maturities	953,884	953,823
Total capitalization	1,990,360	1,903,461
Current Liabilities:		
Short-term debt	35,000	-
Accounts payable	120,918	257,991
Accrued interest and taxes	72,022	36,889
Other current liabilities	101,697	67,758
Total current liabilities	329,637	362,638
Deferred Credits:		
Accumulated deferred income taxes	120,153	166,249
Accumulated deferred investment tax credits	44,714	47,853
Regulatory liabilities	52,890	65,552
Regulatory liabilities related to accumulated deferred income tax	14,163	20,696
Accrued post-retirement benefits cost	14,929	11,899
Other deferred credits	367,792	311,569
Total deferred credits	614,641	623,818
	$ 2,934,638	$ 2,889,917

The accompanying notes are an integral part of these financial statements.

consolidated statements of cash flows

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Cash Flows From Operating Activities:		*(In thousands)*	
Net earnings	$150,433	$100,946	$ 83,155
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	106,768	103,829	103,891
Gain on cumulative effect of a change in accounting principle	-	-	(5,862)
Other	34,874	33,268	26,170
Changes in certain assets and liabilities:			
Accounts receivables	90,639	(90,680)	(16,937)
Other assets	32,481	(32,444)	(20,189)
Accounts payable	(137,073)	107,346	36,670
Other liabilities	46,873	18,682	6,147
Net cash flows provided from operating activities	324,995	240,947	213,045
Cash Flows From Investing Activities:			
Utility plant additions	(264,844)	(146,878)	(95,298)
Return of principal PVNGS lessor's notes	16,674	16,668	16,903
Merger acquisition costs	(11,567)	(6,700)	-
Short-term and long-term investments	(156,107)	(5,307)	(3,076)
Other investing	8,830	(16,715)	25,585
Net cash flows used in investing activities	(407,014)	(158,932)	(55,886)
Cash Flows From Financing Activities:			
Borrowings	35,000	-	11,500
Repayments	-	(32,800)	(58,200)
Exercise of employee stock options	(2,179)	(1,232)	1,453
Common stock repurchase	-	(27,867)	(18,799)
Dividends paid	(31,876)	(32,265)	(33,359)
Other Financing	(560)	(559)	(635)
Net cash flows generated (used) by financing activities	385	(94,723)	(98,040)
Increase (Decrease) in Cash and Cash Equivalents	(81,634)	(12,708)	59,119
Beginning of Year	107,691	120,399	61,280
End of Year	$ 26,057	$107,691	$ 120,399
Supplemental cash flow disclosures:			
Interest paid	$ 62,216	$ 64,045	$ 67,770
Income taxes paid, net of refunds	$ 72,146	$ 50,480	$ 36,575
Acquired pipeline in exchange for transportation services	$ -	$ -	$ 3,100

The accompanying notes are an integral part of these financial statements.

consolidated statements of capitalization

	AS OF DECEMBER 31,	
	2001	2000
Common Stock Equity:	*(In thousands)*	
Common stock, no par value	$ 625,632	$ 627,811
Accumulated other comprehensive income, net of tax	(28,996)	(27)
Retained earnings	415,388	296,843
Total common stock equity	1,012,024	924,627
Minority Interest	11,652	12,211
Cumulative Preferred Stock:		
Without mandatory redemption requirements:		
1965 Series, 4.58% with a stated value of $100.00 and a current redemption price of $102.00. Outstanding shares at December 31, 2001 were 128,000	12,800	12,800
Long-Term Debt:		
Issue and Final Maturity		
First Mortgage Bonds, Pollution Control Revenue Bonds:		
5.700% due 2016	65,000	65,000
6.375% due 2022	46,000	46,000
Total First Mortgage Bonds	111,000	111,000
Senior Unsecured Notes, Pollution Control Revenue Bonds:		
6.300% due 2016	77,045	77,045
5.750% due 2022	37,300	37,300
5.800% due 2022	100,000	100,000
6.375% due 2022	90,000	90,000
6.375% due 2023	36,000	36,000
6.400% due 2023	100,000	100,000
6.300% due 2026	23,000	23,000
6.600% due 2029	11,500	11,500
Total Senior Unsecured Notes, Pollution Control Revenue Bonds	474,845	474,845
Senior Unsecured Notes:		
7.100% due 2005	268,420	268,420
7.500% due 2018	100,025	100,025
Other, including unamortized premium and (discounted), net	(406)	(467)
Total long-term debt	953,884	953,823
Total Capitalization	$1,990,360	$1,903,461

The accompanying notes are an integral part of these financial statements.

consolidated statements of comprehensive income

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
		(In thousands)	
Net Earnings	$150,433	$100,946	$ 83,155
Other Comprehensive Income, net of tax:			
Unrealized gain (loss) on securities:			
Unrealized holding gains arising from the period	(111)	2,794	4,120
Less reclassification adjustment for gains included in net income	(345)	(5,173)	(4,282)
Minimum pension liability adjustment	(28,858)	-	1,387
Mark-to-market adjustment for certain derivative transactions			
Initial implementation of SFAS 133 designated cash flow hedges	6,148	-	-
Change in fair market value of designated cash flow hedges	(345)	-	-
Less reclassification adjustment for gains (losses) in cash flow hedges	(6,148)		
Total Other Comprehensive Income	(28,969)	(2,379)	1,225
Total Comprehensive Income	$121,464	$ 98,567	$ 84,380

The accompanying notes are an integral part of these financial statements.

notes to consolidated financial statements
december 31, 2001, 2000 and 1999

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

PNM Resources, Inc. (the "Company") is a holding company of energy and energy related activities. Its principal subsidiary, Public Service Company of New Mexico ("PNM"), is an integrated public utility primarily engaged in the generation, transmission, distribution and sale and trading of electricity; transmission, distribution and sale of natural gas within the State of New Mexico and the sale and trading of electricity in the Western United States. In addition, the Company provides energy and utility related services under its wholly-owned subsidiary, Avistar, Inc. ("Avistar").

Upon the completion on December 31, 2001, of a one-for-one share exchange between PNM and the Company, the Company became the parent company of PNM. Prior to the share exchange, the Company had existed as a subsidiary of PNM. The new holding company began trading on the New York Stock Exchange under the same PNM symbol beginning on December 31, 2001.

Accounting Principles

The Company prepares its financial statements in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners, and adopted by the New Mexico Public Regulation Commission ("PRC"), the successor of the New Mexico Public Utility Commission ("NMPUC"), effective January 1, 1999.

The Company's accounting policies conform to the provisions of Statement of Financial Accounting Standards No. 71, "*Accounting for the Effects of Certain Types of Regulation*" ("SFAS 71"). SFAS 71 requires a rate-regulated entity to reflect the effects of regulatory decisions in its financial statements. In accordance with SFAS 71, the Company has deferred certain costs and recorded certain liabilities pursuant to the rate actions of the PRC, NMPUC and FERC. These "regulatory assets" and "regulatory liabilities" are enumerated and discussed in the Regulatory Assets and Liabilities note.

To the extent that the Company concludes that the recovery of a regulatory asset is no longer probable due to regulatory treatment, the effects of competition or other factors, the amount would be recorded as a charge to earnings. The Company has discontinued the application of SFAS 71 as of December 31, 1999, for the generation portion of its business effective with the passage of the Electric Utility Industry Restructuring Act of 1999 ("Restructuring Act") in accordance with Statement of Financial Accounting Standards No. 101, "*Accounting for the Discontinuation of Application of FASB Statement No. 71*" ("SFAS 101"). The Company evaluates its regulatory assets under 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"). In 2000, the Company determined certain stranded costs would not be recovered and recorded a charge to earnings for these amounts recorded as stranded cost assets. The Company believes that it will recover costs associated with its remaining stranded cost assets including asset closure costs through a non-bypassable charge as permitted by the Restructuring Act. (See Regulatory Assets and Liabilities note for additional discussion.)

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and subsidiaries in which it owns a majority voting interest or meets the criteria of Emerging Issues Task Force 90-15, Impact of Non-Subtantive Lessors, Residual Value Guarantees and Other Provisions in Leasing Transactions. All significant intercompany transactions and balances have been eliminated.

Financial Statement Preparation and Presentation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual recorded amounts could differ from those estimated.

Utility Plant

Utility plant, with the exception of Palo Verde Nuclear Generating Station ("PVNGS") Unit 3, a portion of San Juan Generating Station ("SJGS") Unit 4 and the Company's owned interests in PVNGS Units 1 and 2, is stated at original cost, which includes capitalized payroll-related costs such as taxes, pension and other fringe benefits, administrative costs and an allowance for funds used during construction. In 1989, PVNGS Unit 3 and a portion of SJGS Unit 4 were excluded from the jurisdictional rate base. As a result, PNM, wrote-down $17.4 million of its carrying cost related to these assets. In 1993, PNM announced specific actions determined to be necessary in order to accelerate PNM's preparation for the competitive electric energy market.

As part of this announcement, PNM stated its intention to attempt to sell PVNGS Unit 3. As a result, PNM wrote-down PVNGS Unit 3 $181.3 million based on the estimated net realizable value of the asset. Since that time, PNM has decided not to sell PVNGS Unit 3. In connection with a rate reduction in 1994, the Company wrote-down $131.6 million of its owned interest in PVNGS Units 1 and 2. Pursuant to a rate stipulation dated October 1993, the Company did not capitalize amounts relating to an allowance for funds used during construction in 2001, 2000 or 1999. Utility plant includes certain electric assets not subject to regulation.

It is Company policy to charge repairs and minor replacements of property to maintenance expense and to charge major replacements to utility plant. Gains or losses resulting from retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

Investments

The Company's investments comprise U.S., state, and municipal government obligations and corporate securities. Investments with maturities of less than one year are considered short-term and are carried at fair value. All investments are held in the Company's name and custodied with major financial institutions. The specific identification method is used to determine the cost of securities disposed of, with realized gains and losses reflected in other income and expense. At December 31, 2001, all of the Company's investments were classified as available-for-sale. Unrealized gains and losses on these investments are included as a separate component of shareholders' equity, net of any related tax effect.

Revenue Recognition

The Company's Utility Operations record electric and gas operating revenues in the period of delivery, which includes estimated amounts for service rendered but unbilled at the end of each accounting period. Utility Operations gas operating revenues exclude adjustments for differences in gas purchase costs that are above or below levels included in base rates but are recoverable under the Purchased Gas Adjustment Clause ("PGAC") administered by the PRC. The Company recognizes this adjustment when it is permitted to bill under PRC guidelines.

The Company's Generation and Trading Operations record operating revenues to the Utility Operations and to third parties in the period of delivery or as services are provided. These electricity sales are recorded as operating revenues while the electricity purchases are recorded as costs of energy sold. These amounts are recorded on a gross basis, because the Company does not act as an agent or broker for these energy trading contracts but takes title and has the risks and rewards of ownership. Certain sales to firm-requirements wholesale customers include a cost of energy adjustment for recoverable fixed costs. The Company recognizes this adjustment when it is permitted to bill under FERC guidelines. Generation and Trading Operations transactions that are net settled, are recorded gross in operating revenues and fuel and purchased power expense. "Net settling"is where the unplanned netting of delivery and acceptance of electric power for convenience of transmission and settlement occurs (referred to as a "bookout").

The Company enters into energy trading contracts to take advantage of market opportunities associated with the purchase and sale of electricity. Unrealized gains and losses resulting from the impact of price movements on the Company's trading contracts are recognized as adjustments to Generation and Trading Operations operating revenues. The market prices used to value these trading transactions reflect management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments.

The cash flow impact of these financial instruments is reflected as cash flows from operating activities in the Consolidated Statement of Cash Flows.

Recoverable Fuel Costs

The Company's fuel and purchased power costs for its firm-requirements wholesale customers that are above the levels included in base rates are recoverable under a fuel and purchased power cost adjustment approved by the FERC. The costs are deferred until the period in which they are billed or credited to customers. The Company's gas purchase costs are recoverable under a similar Purchased Gas Adjustment Clause administered by the PRC.

Depreciation and Amortization
Provision for depreciation and amortization of utility plant is made at annual straight-line rates approved by the PRC. The average rates used are as follows:

	2001	2000	1999
Electric plant	3.39%	3.42%	3.38%
Gas plant	3.19%	3.28%	3.37%
Common plant	6.92%	6.75%	7.73%

The provision for depreciation of certain equipment is allocated to operating expenses or construction projects based on the use of the equipment. Depreciation of non-utility property is computed on the straight-line method. Amortization of nuclear fuel is computed based on the units of production method.

Nuclear Decommissioning
The Company accounts for nuclear decommissioning costs on a straight-line basis over the respective license period. Such amounts are based on the future value of expenditures estimated to be required to decommission the plant.

For gas, the excess or deficiency is accumulated for refund or surcharge to customers on an annual basis. Future recovery of these costs is subject to approval by the PRC.

Amortization of Debt Acquisition Costs
Discount, premium and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. In connection with the retirement of long-term debt, such amounts associated with resources subject to PRC regulation are amortized over the lives of the respective issues. Amounts associated with the Company's firm-requirements wholesale customers and its resources excluded from PRC retail rates are recognized immediately as expense or income as they are incurred.

Financial Instruments
In December 1998, the Emerging Issues Task Force ("EITF") of the Financial Accounting Standards Board ("FASB") reached consensus on EITF Issue No. 98-10 which requires that energy trading contracts should be marked-to-market (measured at fair value determined as of the balance sheet date) with the gains and losses included in earnings. Effective January 1, 1999, the Company adopted EITF Issue No. 98-10. The effect of the initial application of the new standard is reported as a cumulative effect of a change in accounting principle (see Financial Instruments note).

The Company implemented Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities*", ("SFAS 133"), as amended, on January 1, 2001. SFAS 133, as amended, establishes accounting and reporting standards requiring derivative instruments to be recorded in the balance sheet as either an asset or liability measured at their fair value. SFAS 133, as amended, also requires that changes in the derivatives' fair value be recognized currently in earnings unless specific hedge accounting or normal purchase and sale criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133, as amended, provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The results of hedge ineffectiveness and the change in fair value of a derivative that an entity has chosen to exclude from hedge effectiveness are required to be presented in current earnings.

Stock Options
The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "*Accounting for Stock Issued to Employees*". Compensation cost for stock options, if any, is measured as the excess of the quoted market price of the Company's stock at the date of grant over the exercise price of the granted stock option. Restricted stock is recorded as compensation cost over the requisite vesting periods based on the market value on the date of grant.

Statement of Financial Accounting Standards No. 123, *"Accounting for Stock-Based Compensation"* ("SFAS 123"), established accounting and disclosure requirements using a fair-value-based method of accounting for stock-based employee compensation plans. The Company has elected to remain on its current method of accounting as described above, and has adopted the disclosure requirements of SFAS No. 123.

Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109 *"Accounting for Income Taxes"* ("SFAS 109") which uses the asset and liability method for accounting for income taxes. Under SFAS 109, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis. Current PRC jurisdictional rates include the tax effects of the majority of these differences. SFAS No. 109 requires that rate-regulated enterprises record deferred income taxes for differences. SFAS No. 109 requires that rate-regulated enterprises record deferred income taxes for temporary differences accorded flow-through treatment at the direction of a regulatory commission. The resulting deferred tax assets and liabilities are recorded at the expected cash flow to be reflected in future rates. Since the PRC has consistently permitted the recovery of previously flowed-through tax effects, the Company has established regulatory liabilities and assets offsetting such deferred tax assets and liabilities. Items accorded flow-through treatment under PRC orders, deferred income taxes and the future ratemaking effects of such taxes, as well as corresponding regulatory assets and liabilities, are recorded in the financial statements.

Asset Impairment

The Company regularly evaluates the carrying value of its regulatory and tangible long-lived assets in relation to their future undiscounted cash flows to assess recoverability in accordance with SFAS 121. Impairment testing of power generation assets is performed periodically in response to changes in market conditions resulting from industry deregulation. Power generation assets used to supply jurisdictional and wholesale markets are evaluated on a group basis using future undiscounted cash flows based on current open market price conditions. The Company also has generation assets that are used for the sole purpose of reliability. These assets are tested as an individual group. Power generation assets held under operating leases are not currently evaluated for impairment as currently prescribed by GAAP (see Lease Commitments).

Change in Presentation

Certain prior year amounts have been reclassified to conform to the 2001 financial statement presentation.

Segment Information

As it currently operates, the Company's principal business segments are Utility Operations, which include Electric Services ("Electric") and Gas Services ("Gas"), and Generation and Trading Operations ("Generation and Trading"). Electric consists of two major business lines that include distribution and transmission. The transmission business line does not meet the definition of a segment due to its immateriality and is combined with the distribution business line for disclosure purposes.

UTILITY OPERATIONS

Electric

The Company provides jurisdictional retail electric service to a large area of north central New Mexico, including the cities of Albuquerque and Santa Fe, and certain other areas of New Mexico. Approximately 378,000, 369,000 and 361,000 retail electric customers were served by the Company at December 31, 2001, 2000 and 1999, respectively. The Company owns or leases 2,890 circuit miles of transmission lines, interconnected with other utilities in New Mexico and south and east into Texas, west into Arizona, and north into Colorado and Utah.

Electric exclusively acquires its electricity sold to retail customers from the Company's Generation and Trading Operations. Intersegment purchases from the Generation and Trading Operations are priced using internally developed transfer pricing and are not based on market rates. Customer rates for electric service are set by the PRC based on the recovery of the cost of power production and a rate of return that includes certain generation assets that are part of Generation and Trading Operations, among other things.

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Gas

The Company's gas operations distribute natural gas to most of the major communities in New Mexico, including Albuquerque and Santa Fe, serving approximately 443,000, 435,000 and 426,000 customers as of December 31, 2001, 2000 and 1999, respectively. The Company's customer base includes both sales-service customers and transportation-service customers.

In 2000 and the first quarter of 2001, the Company's Generation and Trading Operations procured its gas fuel supply from Gas. In the second quarter of 2001, the Company's Generation and Trading Operations began procuring its gas supply independent of Gas and contracting with Gas for transportation services only.

GENERATION AND TRADING OPERATIONS

The Company's Generation and Trading Operations serve four principal markets. These include sales to the Company's Utility Operations to cover jurisdictional electric demand, sales to firm-requirements wholesale customers, other contracted sales to third parties for a specified amount of capacity (measured in megawatts-MW) or energy (measured in megawatt hours-MWh) over a given period of time and energy sales made on an hourly basis at fluctuating, spot-market rates. In addition to generation capacity, the Company purchases power in the open market. As of December 31, 2001, the total net generation capacity of facilities owned or leased by the Company was 1,653 MW, including a 132 MW power purchase contract accounted for as an operating lease.

UNREGULATED AND OTHER

The Company's wholly-owned subsidiary, Avistar, was formed in August 1999 as a New Mexico corporation and is currently engaged in certain unregulated and non-utility businesses. Unregulated also, includes other immaterial corporate activities and eliminations.

RISKS AND UNCERTAINTIES

The Company's future results may be affected by changes in regional economic conditions; the outcome of labor negotiations with unionized employees; fluctuations in fuel, purchased power and gas prices; the actions of utility regulatory commissions; changes in law; environmental regulations and external factors such as the weather. As a result of state and Federal regulatory reforms, the public utility industry is undergoing a fundamental change. As this occurs, the electric generation business is transforming into a competitive marketplace. The Company's future results will be impacted by its ability to recover its stranded costs, incurred previously in providing power generation to electric service customers, the market price of electricity and natural gas costs and the costs of transition to an unregulated status. In addition, as a result of deregulation, the Company may face competition from companies with greater financial and other resources.

Summarized financial information by business segment for 2001, 2000 and 1999 is as follows:

	UTILITY					
	ELECTRIC	GAS	TOTAL	GENERATION	UNREGULATED AND OTHER	CONSOLIDATED
Twelve Months Ended:			*(In thousands)*			
2001:						
Operating revenues:						
External customers	559,226	385,418	944,644	1,405,916	1,538	2,352,098
Intersegment revenues	707	-	707	341,608	(342,315)	-
Depreciation and amortization	32,666	21,465	54,131	42,766	39	96,936
Interest income	1,626	935	2,561	39,302	6,157	48,020
Net interest charges	19,868	11,807	31,675	28,282	4,883	64,840
Income tax expense (benefit) from continuing operations	26,547	5,710	32,257	90,097	(41,291)	81,063
Operating income (loss)	61,471	20,897	82,368	154,370	(14,061)	222,677
Segment net income (loss)	40,507	8,917	49,424	137,485	(36,476)	150,433
Total assets	770,798	469,410	1,240,208	1,430,917	263,513	2,934,638
Gross property additions	74,316	48,978	123,294	126,605	14,994	264,893

Summarized financial information by business segment for 2001, 2000 and 1999 is as follows:

	UTILITY					
	ELECTRIC	GAS	TOTAL	GENERATION	UNREGULATED AND OTHER	CONSOLIDATED
Twelve Months Ended:			(In thousands)			
2000:						
Operating revenues:						
External customers	538,758	319,924	858,682	750,434	2,158	1,611,274
Intersegment revenues	707	-	707	324,744	(325,451)	-
Depreciation and amortization	31,480	19,994	51,474	41,558	27	93,059
Interest income	1,158	517	1,675	39,439	7,581	48,695
Net interest charges	17,771	11,089	28,860	36,064	518	65,442
Income tax expense (benefit) from continuing operations	30,346	9,632	39,978	45,304	(10,936)	74,346
Operating income (loss)	60,583	22,042	82,625	81,525	(31,676)	132,474
Segment net income (loss)	43,466	14,327	57,793	75,261	(32,108)	100,946
Total assets	689,489	521,636	1,211,125	1,424,586	254,206	2,889,917
Gross property additions	51,815	40,418	92,233	53,025	1,620	146,878

	UTILITY					
	ELECTRIC	GAS	TOTAL	GENERATION	UNREGULATED AND OTHER	CONSOLIDATED
Twelve Months Ended:			(In thousands)			
1999:						
Operating revenues:						
External customers	540,868	236,711	777,579	371,109	8,855	1,157,543
Intersegment revenues	707	-	707	318,872	(319,579)	-
Depreciation and amortization	30,183	19,210	49,393	41,183	2,085	92,661
Interest income	76	1,066	1,142	39,439	7,581	48,162
Net interest charges	19,822	13,585	33,407	36,561	699	70,667
Income tax expense (benefit) from continuing operations	24,174	2,299	26,473	25,086	(9,250)	42,309
Operating income (loss)	58,331	16,102	74,433	57,999	(12,353)	120,079
Cumulative effect of a change in accounting principle, net of tax	-	-	-	3,541	-	3,541
Segment net income (loss)	38,061	2,780	40,841	56,506	(14,192)	83,155
Total assets	715,620	449,790	1,165,410	1,464,423	93,435	2,723,268
Gross property additions	42,253	27,150	69,403	23,899	2,334	95,636

Regulatory Assets and Liabilities

The Company is subject to the provisions of SFAS 71, with respect to operations regulated by the PRC. Regulatory assets represent probable future revenue to the Company associated with certain costs, which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31, relate to the following:

	2001	2000
Assets:	*(In thousands)*	
Current:		
PGAC	$ 9,065	$ 46,390
Gas take-or-pay costs	1,408	1,214
Subtotal	10,473	47,604
Deferred:		
Deferred income taxes	33,632	33,848
Loss on reacquired debt	6,798	7,687
Gas imputed revenues	2,310	2,117
Deferred customer expense on gas assets sale	-	7,984
Gas retirees' health care costs	-	1,724
Proposed transmission line costs	2,222	2,377
Other	1,459	1,888
Subtotal	46,421	57,625
Stranded and Transition Assets	151,527	170,630
Total assets	208,421	275,859
Liabilities:		
Deferred:		
Deferred income taxes	(41,915)	(43,834)
Gas regulatory reserve	(565)	(980)
Customer gain on gas assets sale	-	(7,226)
Line acquisition	(1,954)	(2,490)
Gain on reacquired debt	(1,640)	(1,791)
Other	(332)	(568)
Subtotal	(46,406)	(56,889)
Stranded and Transition Liabilities	(20,647)	(29,359)
Total liabilities	(67,053)	(86,248)
Net regulatory assets	$141,368	$189,611

Substantially all of the Company's regulatory assets and regulatory liabilities are reflected in rates charged to customers or have been addressed in a regulatory proceeding. The Company does not receive or pay a material rate of return on these regulatory assets and regulatory liabilities.

The Restructuring Act, as amended, recognizes that electric utilities should be permitted a reasonable opportunity to recover an appropriate amount of the costs previously incurred in providing electric service to their customers ("stranded costs"). Stranded costs represent all costs associated with generation related assets, currently in rates or determined to be recoverable in rates, in excess of the expected competitive market price and include plant decommissioning costs, regulatory assets, and lease and lease-related costs. Utilities will be allowed to recover no less than 50% of stranded costs through a non-bypassable charge on all customer bills for five years after implementation of customer choice. The PRC could authorize a utility to recover up to 100% of its stranded costs if the PRC finds that recovery of more than 50%: (i) is in the public interest; (ii) is necessary to maintain the financial integrity of the public utility; (iii) is necessary to continue adequate and reliable service; and (iv) will not cause an increase in rates to residential or small business customers during the transition period. The Restructuring Act also allows for the recovery of nuclear decommissioning costs by means of a separate wires charge over the life of the underlying generation assets.

Approximately $142 million of costs associated with the unregulated businesses under the Restructuring Act were established as regulatory assets. Because of the Company's belief that recovery through rates is probable as established by law, these assets continue to be classified as regulatory assets, although the Company's Generation and Trading Operations has discontinued SFAS 71 and adopted SFAS 101.

In 2001, the Company recognized the write-off of $13.0 million of non-recoverable coal mine decommissioning costs previously established as a regulatory asset. As a result of the Company's evaluation of its regulatory strategy in light of its holding company filing in May 2001, management determined that it would not seek recovery of a portion of its previously established stranded cost asset that was not a component of retail ratemaking. The remaining portion of costs associated with coal mine decommissioning that are attributed to local jurisdictional customers will be sought in future rate cases. The amendments to the Restructuring Act provide the opportunity for amortization of coal mine decommissioning costs currently estimated at approximately $100 million. The Company intends to seek recovery of these costs in its next rate case filing and believes that the costs are fully recoverable. The Company believes that any remaining portion of the regulatory assets will be fully recovered in future rates, including through a non-bypassable wires charge.

Pursuant to the Restructuring Act, utilities will also be allowed to recover in full any prudent and reasonable costs incurred in implementing full open access ("transition costs"). The transition costs are presently scheduled to be recovered beginning 2007 through 2012 by means of a separate wires charge. The Company intends to seek recovery of incurred transition costs in any future rate proceeding held before open access begins. Transition costs include professional fees, financing costs including underwriting fees, costs relating to the transfer of assets, the cost of management information system changes including billing system changes and public and customer communications costs.

On December 31, 2001, the Company implemented a holding company structure without separation of supply service and energy-related service assets from distribution and transmission service assets as permitted under the amended Restructuring Act. The Company is unable to predict the form its further restructuring will take under delayed implementation of customer choice. Accordingly, it cannot estimate the total expected amount of transition costs. Recoverable transition costs will be capitalized and amortized over the recovery period to match related revenues. Costs not recoverable will be expensed when incurred unless otherwise capitalizable under the accounting rules.

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Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31, related to stranded or transition costs are as follows:

	2001	2000
Assets:	*(In thousands)*	
Transition costs	$ 13,208	$ 19,069
Mine reclamation costs	100,877	113,856
Deferred income taxes	35,775	35,726
Loss on reacquired debt	1,667	1,979
Subtotal	151,527	170,630
Liabilities:		
Deferred income taxes	(14,163)	(20,696)
PVNGS prudence audit	(5,058)	(5,434)
Settlement due customers	(1,408)	(3,205)
Gain on reacquired debt	(18)	(24)
Subtotal	(20,647)	(29,359)
Net stranded cost and transition cost	$130,880	$141,271

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its net regulatory assets are probable of future recovery.

Capitalization

Changes in common stock and retained earnings are as follows:

	COMMON STOCK		
	NUMBER OF SHARES	AGGREGATE PAR VALUE	RETAINED EARNINGS
		(Dollars in thousands)	
Balance at December 31, 1999	40,703,383	$656,910	$227,829
Stock repurchases	(1,585,584)	(27,867)	-
Tax benefit from exercise of stock option	-	(1,232)	-
Net earnings	-	-	100,946
Dividends:			
Cumulative preferred stock	-	-	(586)
Common stock	-	-	(31,346)
Balance at December 31, 2000	39,117,799	627,811	296,843
Stock repurchase	-	-	-
Exercise of stock options	-	(2,179)	-
Net earnings	-	-	150,433
Dividends:			
Cumulative preferred stock	-	-	(586)
Common stock	-	-	(31,302)
Balance at December 31, 2001	39,117,799	$625,632	$415,388

Common Stock

The number of authorized shares of common stock of the Company is 120 million shares with no par value. The declaration of common dividends is dependent upon a number of factors including the ability of the Company's subsidiaries to pay dividends. Currently, PNM is the Company's primary source of dividends. As part of the order approving the formation of the holding company, the PRC placed certain restrictions on the ability of PNM to pay dividends to its parent.

The PRC order imposed the following conditions regarding dividends paid by PNM to the holding company: PNM can not pay dividends which cause its debt rating to go below investment grade; and PNM can not pay dividends in any year, as determined on a rolling four quarter basis, in excess of net earnings without prior PRC approval. Additionally, PNM has various financial covenants which limit the transfer of assets, through dividends or other means.

In addition, the ability of the Company to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of retained earnings, the financial circumstances and performance, the PRC's decisions in various regulatory cases currently pending and which may be docketed in the future, the effect of deregulating generation markets and market economic conditions generally. The ability to recover stranded costs in deregulation (as amended), conditions imposed on holding company formation, future growth plans and the related capital requirements and standard business considerations may also affect the Company's ability to pay dividends.

Consistent with the PRC's holding company order, PNM paid dividends of $127.0 million to the Company on December 31, 2001. On March 4, 2002, the PNM Board of Directors declared an additional dividend of approximately $5.5 million, which was paid March 19, 2002.

On February 19, 2002, the Company's Board of Directors approved a 10 percent increase in the common stock dividend. The increase raises the quarterly dividend to $0.22 per share, for an indicated annual dividend of $0.88 per share. The Company's Board of Directors approved a policy for future dividend increases in the range of 8 to 10 percent annually, targeting a payout of between 50 to 60 percent of regulated earnings. The Company believes that this target is consistent with the Company's expectation of future operating cash flows and the cash needs of its planned increase in generating capacity.

In March 1999, PNM's Board of Directors approved a plan to repurchase up to 1,587,000 shares of its outstanding common stock with maximum purchase price of $19.00 per share. In December 1999, PNM Board of Directors authorized PNM to repurchase up to an additional $20.0 million of its common stock. As of December 31, 1999, PNM repurchased 1,070,700 shares of its previously outstanding common stock at a cost of $18.8 million. From January 2000 through March 2000, PNM repurchased an additional 1,167,684 shares of its outstanding common stock at a cost of $18.8 million.

On August 8, 2000, PNM's Board of Directors approved a plan to repurchase up to $35 million of its outstanding common stock through the end of the first quarter of 2001. From August 8, 2000 through December 31, 2000, PNM repurchased an additional 417, 900 shares of its outstanding common stock at a cost of $9.0 million. The total cost of stock repurchased for the year ended December 31, 2000 was $27.9 million. There were no repurchases of stock during the year ended December 31, 2001. The Board of Directors has authorized additional stock repurchases but the Company has not exercised that new authority.

Cumulative Preferred Stock

No company preferred stock is outstanding. The Company's restated articles of incorporation authorizes 10 million shares of preferred stock, which may be issued without restriction. PNM has 128,000 shares, 1965 Series, 4.58%, stated value of $100 per share, of cumulative preferred stock outstanding. The 1965 Series does not have a mandatory redemption requirement but may be redeemable at 102% of the par value with accrued dividends. The holders of the 1965 Series are entitled to payment before holders of common stock in the event of any liquidation or dissolution or distribution of assets of PNM. In addition, the 1965 Series is not entitled to a sinking fund and cannot be converted into any other class of stock of PNM.

Long-Term Debt

PNM has $268,420,000 of long-term debt that matures in August 2005. All other long-term debt matures in 2016 or later.

On March 11, 1998, PNM modified its 1947 Indenture of Mortgage and Deed of Trust; no future bonds can be issued under the mortgage. While first mortgage bonds continue to serve as collateral for PCBs in the outstanding principal amount of $111 million, the lien of the mortgage covers only PNM's ownership interest in PVNGS. Senior unsecured notes ("SUNs"), which were issued under a senior unsecured note indenture, serve as collateral for PCBs in the outstanding principal amount of $463.3 million. With the exception of the $111 million of PCBs secured by first mortgage bonds, the SUNs are and will be the senior debt of PNM.

In August 1998, PNM issued and sold $435 million of SUNs in two series, the 7.10% Series A due August 1, 2005, in the principal amount of $300 million, and the 7.50% Series B due August 1, 2018, in the principal amount of $135 million. These SUNs were issued under an indenture similar to the indenture under which the SUNs were issued and it is expected that future long-term debt financings will be similarly issued. In 1999, PNM retired $31.6 million of its 7.10% senior unsecured notes through open market purchases, utilizing the funds from operations and the funds from temporary investments leaving an outstanding principal balance of $268.4 million. In January 2000, PNM retired $35.0 million of its 7.5% senior unsecured notes through open market purchases utilizing funds from operations and the funds from temporary investments leaving an outstanding principal balance of $100.0 million. The gains recognized on these purchases were immaterial.

On October 28, 1999, tax-exempt pollution control revenue bonds of $11.5 million with an interest rate of 6.60% were issued by PNM to provide partial reimbursement for expenditures associated with its share of a recently completed upgrade of the emission control system at SJGS.

Revolving Credit Facility and Other Credit Facilities

At December 31, 2001, PNM had a $150 million unsecured revolving credit facility (the "Facility") with an expiration date of March 11, 2003. The Company must pay commitment fees of 0.1875% per year on the total amount of the Facility. PNM also had $20 million in local lines of credit. In addition, the Company has $25 million in local lines of credit.

There were $35.0 million in outstanding borrowings, bearing interest at 2.3875%, under the Facility as of December 31, 2001. On January 31, 2002, this amount was refunded at an interest rate of 2.325%. Subsequent to December 31, 2001, an additional $40.0 million was borrowed at an interest rate of 2.20%, which was subsequently refunded at an interest rate of 2.3875% as of March 1, 2002. The Company was in compliance with all covenants under the Facility.

Lease Commitments

PNM leases interests in Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. Covenants in PNM's PVNGS Units 1 and 2 lease agreements limit PNM's ability, without consent of the owner participants in the lease transactions, (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions.

In 1998, PNM established PVNGS Capital Trust ("Capital Trust"), for the purpose of acquiring all the debt underlying the PVNGS leases. PNM consolidates Capital Trust in its consolidated financial statements. The purchase was funded with the proceeds from the issuance of $435 million of SUNS (see Capitalization note), which were loaned to Capital Trust. Capital Trust then acquired and holds the debt component of the PVNGS leases. For legal and regulatory reasons, the PVNGS lease payment continues to be recorded and paid gross with the debt component of the payment returned to PNM via Capital Trust. As a result, the net cash outflows for the PVNGS lease payment were $12.4 million in 2001. The summary of PNM's future minimum operating lease payments below, reflects the net cash outflow related to the PVNGS leases.

PNM's other significant operating lease obligations include a transmission line with annual lease payments of $7.3 million and a power purchase agreement for the entire output of a gas-fired generating plant in Albuquerque, New Mexico with imputed annual lease payments of $6.0 million.

Future minimum operating lease payments (in thousands) at December 31, 2001 are:

2002	$ 32,095
2003	33,049
2004	33,113
2005	34,769
2006	35,587
Later years	364,341
Total minimum lease payments	$ 532,954

Operating lease expense, inclusive of the net PVNGS lease payment, was approximately $32.7 million in 2001, $28.5 million in 2000 and $23.7 million in 1999. Aggregate minimum payments to be received in future periods under non-cancelable subleases are approximately $5.3 million.

Financial Instruments

The estimated fair value of the Company's financial instruments (including current maturities) at December 31, is as follows:

	2001		2000	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
	(In thousands)			
Short-term and long-term investment securities	$150,781	$150,781	$ -	$ -
Long-term debt	$953,884	$973,975	$953,823	$930,359
Investment in PVNGS lessors' notes	$387,347	$453,028	$405,960	$440,079
Decommissioning trust	$ 57,284	$ 57,284	$ 54,977	$ 54,977
Fossil-fueled plant decommissioning trust	$ -	$ -	$ 4,760	$ 4,760
Rabbi trust	$ 10,848	$ 10,848	$ 14,281	$ 14,281

Fair value is based on market quotes provided by the Company's investment bankers and trust advisors.

The carrying amounts reflected on the consolidated balance sheets approximate fair value for cash, temporary investments, and receivables and payables due to the short period of maturity.

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electric prices, interest rates of future debt issuances and adverse market changes for investments held by the Company's various trusts. The Company also uses certain derivative instruments for bulk power electricity trading purposes in order to take advantage of favorable price movements and market timing activities in the wholesale power markets.

The Company is exposed to credit risk in the event of non-performance or non-payment by counterparties of its financial derivative instruments. The Company uses a credit management process to assess and monitor the financial conditions of counterparties. The Company's credit risk with its largest counterparty as of December 31, 2001 and 2000 was $7.5 million and $16.7 million respectively.

Natural Gas Contracts

UTILITY OPERATIONS

Pursuant to a 1997 order issued by the NMPUC, predecessor to the PRC, the Company has previously entered into swaps to hedge certain portions of natural gas supply contracts in order to protect the Company's natural gas customers from the risk of adverse price fluctuations in the natural gas market. The financial impact of all hedge gains and losses from swaps is recoverable through the Company's purchased gas adjustment clause as deemed prudently incurred by the PRC. As a result, earnings are not affected by gains or losses generated by these instruments.

The Company purchased gas options, a type of hedge, to protect its natural gas customers from price risk during the 2001-2002 heating season. The Company expended $9.4 million to purchase options that limit the maximum amount the Company would pay for gas during the winter heating season. The Company recovered its actual hedging expenditures as a component of the PGAC during the months of October 2001 through February 2002 in equal allotments of $1.88 million. As winter 2001-2002 gas prices were substantially lower than the previous year, the hedges placed for this winter expired unexercised.

GENERATION AND TRADING

Commencing in 2000, the Company's Generation and Trading Operations conducted a hedging program to reduce its exposure to fluctuations in prices for natural gas used as a fuel source for some of its generation. The Generation and Trading Operations purchased futures contracts for a portion of its anticipated natural gas needs in the second, third and fourth quarters of 2001. The futures contracts capped the Company's natural gas purchase prices at $5.08 to $6.40 per MMBTU and had a notional amount of $33.6 million. Simultaneously, a delivery location basis swap was purchased for quantities corresponding to the futures quantities to protect against price differential changes at the specific delivery points. The Company accounted for these transactions as cash flow hedges; accordingly, gains and losses related to these transactions are deferred and recorded as a component of Other Comprehensive Income. These gains and losses were reclassified and recognized in earnings as an adjustment to the Company's cost of fuel when the hedged transaction affected earnings. The fuel hedge program ended in December 2001.

Electricity Trading Contracts

For the year ended December 31, 2001, the Company's wholesale electric trading operations settled trading contracts for the sale of electricity that generated $77.9 million of electric revenues by delivering 448,000 MWh. The Company purchased $76.7 million or 428,000 MWh of electricity to support these contractual sales and other open market sales opportunities. For the year ended December 31, 2000, the Company's wholesale electric trading operations settled trading contracts for the sale of electricity that generated $88.9 million of electric revenues by delivering 2.1 million KWh. The Company purchased $78.6 million or 1.9 million KWh of electricity to support these contractual sales and other open market sales opportunities.

As of December 31, 2001, the Company had open trading contract positions to buy $66.9 million and to sell $25.7 million of electricity. At December 31, 2001, the Company had a gross mark-to-market gain (asset position) on these trading contracts of $10.9 million and gross mark-to-market loss (liability position) of $41.4 million, with net mark-to-market loss (liability position) of $30.5 million. The change in mark-to-market valuation is recognized in earnings each period.

In addition, the Company's Generation and Trading Operations enter into forward physical contracts for the sale of the Company's electric capacity in excess of its jurisdictional needs, including reserves, or the purchase of jurisdictional needs, including reserves, when resource shortfalls exist. The Company generally accounts for these derivative financial instruments as normal sales and purchases as defined by SFAS 133, as amended. The Company from time to time makes forward purchases to serve its jurisdictional needs when the cost of purchased power is less than the incremental cost of its generation. At December 31, 2001, the Company had open forward positions classified as normal sales of electricity of $48.9 million and normal purchases of electricity of $8.1 million.

The Company's Generation and Trading Operations, including both firm commitments and trading activities, are managed through an asset backed strategy, whereby the Company's aggregate net open position is covered by its own excess generation capabilities. The Company is exposed to market risk if its generation capabilities were disrupted or if its jurisdictional load requirements were greater than anticipated. If the Company were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases.

Forward Starting Interest Rate Swaps

PNM currently has $182.0 million of tax-exempt bonds outstanding that are callable at a premium in December 2002 and August 2003. PNM intends to refinance these bonds assuming the interest rate of the refinancing does not exceed the current interest rate and has hedged the entire planned refinancing. In order to take advantage of current low interest rates, PNM entered into two forward starting interest rate swaps in November and December 2001 and three additional contracts subsequent to December 31, 2001. PNM designated these swaps as cash flow hedges. The hedged risks associated with these instruments are the changes in cash flows related to general moves in interest rates expected for the refinancing. The swaps effectively cap the interest on the refinancing to 4.9% plus an adjustment for PNM's and the industry's credit rating. PNM's assessment of hedge effectiveness is based on changes in the interest rates and PNM's credit spread. SFAS 133, as amended, provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transactions affects earnings. Any hedge ineffectiveness is required to be presented in current earnings. There was no material hedge ineffectiveness in the year ended December 31, 2001.

A forward starting swap does not require any upfront premium and captures changes in the corporate credit component of an investment grade company's interest rate as well as the underlying Treasury benchmark. The five forward interest rate swaps have termination dates and notional amounts as follows: one with a termination date of September 17, 2002 for a notional amount of $46.0 million and four with a termination date of May 15, 2003 for a combined notional amount of $136.0 million. There were no fees on the transaction, as they are imbedded in the rates, and the transaction is cash settled on the mandatory unwind date (strike date), corresponding to the refinancing date of the underlying debt. The settlement will be capitalized as a cost of issuance and amortized over the life of the debt as a yield adjustment.

Hedge of Trust Assets

In February 2001, PNM terminated certain financial derivatives based on the Standard & Poor's ("S&P") 500 Index. These instruments were used to limit potential loss on investments for nuclear decommissioning, executive retirement and retiree medical benefits due to adverse market fluctuations. PNM recognized a realized gain of $0.5 million (pretax) as a result. Previously, changes in fair market value were recorded in PNM's result of operations.

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Earnings Per Share

In accordance with SFAS No. 128, Earnings per Share, dual presentation of basic and diluted earnings per share has been presented in the Consolidated Statements of Earnings. The following reconciliation illustrates the impact on the share amounts of potential common shares and the earnings per share amounts:

	2001	2000	1999
		(In thousands)	
Basic:			
Net Earnings from Continuing Operations	$150,433	$100,946	$79,614
Cumulative Effect of a Change in Accounting Principle, net of tax	-	-	3,541
Net Earnings	150,433	100,946	83,155
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$149,847	$100,360	$82,569
Average Number of Common Shares Outstanding	39,118	39,487	41,038
Net Earnings per Share of Common Stock:			
Earnings from continuing operations	$ 3.83	$ 2.54	$ 1.93
Cumulative effect of a change in accounting principle	-	-	0.08
Net Earnings per Share of Common Stock (Basic)	$ 3.83	$ 2.54	$ 2.01
Diluted:			
Net Earnings from Continuing Operations	$150,433	$100,946	$79,614
Cumulative effect of a change in accounting principle, net of tax	-	-	3,541
Net Earnings	150,433	100,946	83,155
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$149,847	$100,360	$82,569
Average Number of Common Shares Outstanding	39,118	39,487	41,038
Diluted Effect of Common Stock Equivalents (a)	613	223	65
Average Common and Common Equivalent Shares Outstanding	39,731	39,710	41,103
Net Earnings per Share of Common Stock:			
Earnings from continuing operations	$ 3.77	$ 2.53	$ 1.93
Cumulative effect of a change in accounting principle	-	-	0.08
Net Earnings per Share of Common Stock (Diluted)	$ 3.77	$ 2.53	$ 2.01

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out of-the-money options of 105,336 and 66,143 for the years ended 2000 and 1999, respectively. There were no anti-dilutive common stock equivalents in 2001.

Income Taxes

Income taxes before discontinued operations and cumulative effect of a change in accounting principle consist of the following components:

	2001	2000	1999
		(In thousands)	
Current Federal income tax	$ 97,661	$ 41,666	$ 23,511
Current state income tax	21,220	13,726	8,502
Deferred Federal income tax	(28,967)	19,729	13,494
Deferred state income tax	(5,712)	2,368	210
Amortization of accumulated investment tax credits	(3,139)	(3,143)	(3,409)
Total income taxes	$ 81,063	$ 74,346	$ 42,308
Charged to operating expenses	$ 88,769	$ 53,964	$ 25,010
Charged to other income and deductions	(7,706)	20,382	17,298
Total income taxes	$ 81,063	$ 74,346	$ 42,308

The Company's provision for income taxes before discontinued operations and cumulative effect of a change in accounting principle differed from the Federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

	2001	2000	1999
		(In thousands)	
Federal income tax at statutory rates	$ 81,024	$ 61,352	$ 42,673
Investment tax credits	(3,139)	(3,143)	(3,409)
Depreciation of flow-through items	2,249	2,250	605
Gains on the sale and leaseback of PVNGS Units 1 and 2	(527)	(527)	(527)
Equity income from passive investments	(1,180)	-	(1,301)
Annual reversal of deferred income taxes accrued at prior tax rates	(1,963)	(2,477)	(2,320)
Valuation reserve for regulatory recoverability	(6,552)	6,552	-
State income tax	10,706	8,343	5,541
Other	445	1,996	1,046
Total income taxes	$ 81,063	$ 74,346	$ 42,308
Effective tax rate	35.02%	42.41%	34.70%

The components of the net accumulated deferred income tax liability were:

	2001	2000
	(In thousands)	
Deferred Tax Assets:		
Nuclear decommissioning costs	$ 28,138	$ 23,892
Regulatory liabilities related to income taxes	40,594	41,695
Other	78,973	69,469
Total deferred tax assets	147,705	135,056
Deferred Tax Liabilities:		
Depreciation	189,157	184,127
Investment tax credit	44,714	47,853
Fuel costs	5,515	24,808
Regulatory assets related to income taxes	68,086	67,435
Other	19,263	45,631
Total deferred tax liabilities	326,735	369,854
Accumulated deferred income taxes, net	$179,030	$234,798

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the consolidated statement of earnings for the period:

Net change in deferred income tax liability per above table	$ (55,768)
Change in tax effects of income tax related regulatory assets and liabilities	(1,752)
Tax effect of mark-to-market on investments available for sale	790
Tax effect of excess pension liability	18,912
Deferred income tax expense from continuing operations for the period	$ (37,818)

The Company has no net operating loss carryforwards as of December 31, 2001.

The Company defers investment tax credits related to rate regulated assets and amortizes them over the estimated useful lives of those assets. The Company anticipates that this practice will continue when the generation assets are no longer rate regulated upon full implementation of the Restructuring Act.

Pension and Other Postretirement Benefits

Pension Plan

The Company and its subsidiaries have a pension plan covering substantially all of their union and non-union employees, including officers. The plan is non-contributory and provides for benefits to be paid to eligible employees at retirement based primarily upon years of service with the Company and the average of their highest annual base salary for three consecutive years. The Company's policy is to fund actuarially-determined contributions. Contributions to the plan reflect benefits attributed to employees' years of service to date and also for services expected to be provided in the future. Plan assets primarily consist of common stock, fixed income securities, cash equivalents and real estate.

In December 1996, the Board of Directors approved changes to the Company's non-contributory defined benefit plan ("Retirement Plan") and the implementation of a 401(k) defined contribution plan effective January 1, 1998. Salaries used in Retirement Plan benefit calculations were frozen as of December 31, 1997. Additional credited service can be accrued under the Retirement Plan up to a limit determined by age and years of service. The Company contributions to the 401(k) plan consist of a 3 percent non-matching contribution, and a 75 percent match on the first 6 percent contributed by the employee on a before-tax basis. The Company contributed $9.0, $8.9 and $8.4 million in the years ended December 31, 2001, 2000 and 1999, respectively.

The following sets forth the pension plan's funded status, components of pension costs and amounts (in thousands) at the plan valuation date of September 30:

	PENSION BENEFITS	
	2001	2000
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$313,152	$331,061
Service cost	5,544	6,491
Interest cost	25,758	23,572
Amendments	3,560	-
Actuarial gain (loss)	44,420	(30,934)
Benefits paid	(19,000)	(17,038)
Benefit obligation at end of period	373,434	313,152
Change in Plan Assets:		
Fair value of plan assets at beginning of year	389,827	361,640
Actual return on plan assets	(30,989)	45,225
Benefits paid	(19,000)	(17,038)
Fair value of plan assets at end of year	339,838	389,827
Funded Status	(33,596)	76,675
Unamortized transition assets	-	(1,158)
Unrecognized net actuarial gain (loss)	48,432	(57,445)
Unrecognized prior service cost	3,571	44
Prepaid pension cost	$ 18,407	$ 18,116
Weighted - Average Assumptions as of September 30,		
Discount rate	7.50%	8.25%
Expected return on plan assets	7.75%	9.00%

	PENSION BENEFITS		
	2001	2000	1999
Components of Net Periodic Benefit Cost:			
Service cost	$ 5,544	$ 6,491	$ 7,407
Interest cost	25,758	23,572	21,777
Expected return on plan assets	(29,488)	(30,923)	(27,466)
Amortization of prior service cost	(1,971)	(1,130)	(1,130)
Net periodic pension costs (benefit)	$ (157)	$ (1,990)	$ 588

Other Postretirement Benefits

The Company provides medical and dental benefits to eligible retirees. Currently, retirees are offered the same benefits as active employees after reflecting Medicare coordination. The following sets forth the plan's funded status, components of net periodic benefit cost (in thousands) at the plan valuation date of September 30:

	OTHER BENEFITS	
	2001	2000
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$ 81,711	$ 73,765
Service cost	2,644	1,053
Interest cost	7,906	5,428
Actuarial loss	17,147	1,465
Benefit obligation at end of period	109,408	81,711
Change in Plan Assets:		
Fair value of plan assets at beginning of year	44,693	41,825
Actual return on plan assets	(5,161)	3,661
Employer contribution	6,153	1,431
Benefits paid	(3,553)	(2,224)
Fair value of plan assets at end of year	42,132	44,693
Funded Status	(67,276)	(37,018)
Unamortized transition assets	19,988	3,181
Unrecognized prior service cost	31,763	21,805
Accrued postretirement (costs)	$ (15,525)	$ (12,032)
Weighted – Average Assumptions as of September 30,		
Discount rate	7.50%	8.25%
Expected return on plan assets	8.25%	9.00%

	OTHER BENEFITS		
	2001	2000	1999
Components of Net Periodic Benefit Cost:			
Service cost	$ 2,644	$ 1,053	$ 1,402
Interest cost	7,906	5,428	4,782
Expected return on plan assets	(3,412)	(3,572)	(3,135)
Amortization of prior service cost	2,616	1,817	1,817
Net periodic postretirement benefit cost	$ 9,754	$ 4,726	$ 4,866

The effect of a 1% increase in the health care trend rate assumption would increase the accumulated postretirement benefit obligation as of September 30, 2001, by approximately $18.5 million and the aggregate service and interest cost components of net periodic postretirement benefit cost for 2001 by approximately $2.0 million. The health care cost trend rate is expected to decrease to 6.0% by 2010 and to remain at that level thereafter.

Executive Retirement Program

The Company has an executive retirement program for a group of management employees. The program was intended to attract, motivate and retain key management employees. The Company's projected benefit obligation and accumulated benefit obligation for this program, as of December 31, 2001 and 2000, was $17.7 million and $16.9 million, respectively. As of the plan valuation date of September 30, 2001 and 2000, the Company has recognized an additional liability of $2.8 million and $2.0 million respectively, for the amount of unfunded accumulated benefits in excess of accrued pension costs. The net periodic cost for 2001, 2000 and 1999 was $1.7 million, $1.9 million and $2.3 million, respectively. In 1989, the Company established an irrevocable grantor trust in connection with the executive retirement program. Under the terms of the trust, the Company may, but is not obligated to, provide funds to the trust, which was established with an independent trustee, to aid it in meeting its obligations under the program. Marketable securities in the amount of approximately $10.2 million (fair market value of $10.9 million) are presently in trust. No additional funds have been provided to the trust since 1989.

Stock Option Plans

The Company's Performance Stock Plan ("PSP") expired on December 31, 2000. The PSP was a non-qualified stock option plan, covering a group of management employees. Options to purchase shares of the Company's common stock were granted at the fair market value of the shares on the date of the grant. Options granted through December 31, 1995 vested on June 30, 1996 and have an exercise term of up to 10 years. All subsequent awards granted between December 31, 1995 and February 2000, vest three years from the grant date of the awards. Options granted or approved on or after February 9, 1998, can also vest upon retirement. Awards granted in December 2000 vest ratably over three years on the anniversary of the grant date. The maximum number of options authorized was 5.0 million shares that could be granted through December 31, 2000. Although the authority to grant options under the PSP expired on December 31, 2000, the options that were granted continue to be effective according to their terms.

A new employee stock incentive plan, the Omnibus Performance Equity Plan (the "Omnibus Plan"), became effective on the formation of the holding company on December 31, 2001. The Omnibus Plan provides for the granting of non-qualified stock options, incentive stock options, restricted stock rights, performance shares, performance units and stock appreciation rights to officers and key employees. The total number of shares of common stock subject to awards under the Omnibus Plan may not exceed 2.5 million, subject to adjustment under certain circumstances defined in the Omnibus Plan. In addition, the grant of restricted stock rights, performance shares and units and stock appreciation rights is limited to 500,000 shares. Re-pricing of stock options is prohibited unless specific shareholder approval is obtained. No grants were made in 2001.

Stock options may also be provided to non-employee directors of the Company under the Company's Director Retainer Plan ("DRP"). Prior to December 31, 2001, non-employee directors could elect to receive payment of the annual retainer in the form of cash, restricted stock or options to purchase shares of the Company's common stock. The number of options granted in 2001 and 2000 under this DRP was 6,000 shares with an exercise price of $22.61 and 6,000 shares with an exercise price of $6.19, respectively. 4,000 options were exercised under this DRP during both 2001 and 2000. The number of options outstanding as of December 31, 2001, was 33,000. Restricted Stock issuances were based on the fair market value of the Company's common stock on the date of grant and vest ratably three years on the anniversary of the grant date. As of December 31, 2001, there were no restricted stock outstanding under the DRP plan. Amendments to the DRP were approved by the shareholders on July 3, 2001 and the amended plan became the DRP for the new holding company on December 31, 2001. Under the new DRP, the maximum number of authorized shares was increased from 100,000 to 200,000 (including shares previously granted) through July 1, 2005. The annual retainer is payable in cash and stock options. Restricted stock is no longer available under the plan. The exercise price of stock options granted under the DRP is determined by the fair market value of the stock on the grant date.

A summary of the status of the Company's stock option plans at December 31, and changes during the years then ended is presented below. Prior periods have been restated for comparability purposes.

	2001		2000		1999	
FIXED OPTIONS	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	3,336,221	$19.120	1,574,418	$18.187	1,014,242	$18.819
Granted	6,000	$22.610	2,078,500	$19.403	608,708	$17.397
Exercised	299,951	$19.610	296,027	$16.290	-	N/A
Forfeited	60,969	$17.961	20,670	$17.320	48,532	$18.649
Outstanding at end of year	2,981,301		3,336,221		1,574,418	
Options exercisable at year-end	981,197		916,263		766,454	
Options available for future grant	2,500,000		-		2,183,624	

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The following table summarizes information about stock options outstanding at December 31, 2001:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE FIXED OPTIONS	NUMBER OUTSTANDING AT 12/31/01	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICES	NUMBER EXERCISABLE AT 12/31/01	WEIGHTED AVERAGE EXERCISE PRICES
$5.50 - $22.61	33,000	7.136 years	$ 11.020	27,000	$ 8.444
$11.50 - $24.313	2,948,301	7.783 years	$ 19.194	954,197	$ 20.435
	2,981,301	7.776 years	$ 19.103	981,197	$ 20.105

Had compensation expense for the Company's stock options been recognized based on the fair value on the grant date under the methodology prescribed by SFAS No. 123. The effect on the Company's pro forma net earnings and pro forma earnings per share would be as follows (in thousands, except per share data):

	2001		2000		1999	
	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA	AS REPORTED	PRO FORMA
Net earnings: (available for common)	$149,847	$146,417	$100,360	$96,735	$82,569	$81,573
Net earnings per share						
Basic	$ 3.83	$ 3.74	$ 2.54	$ 2.45	$ 2.01	$ 1.99
Diluted	$ 3.77	$ 3.69	$ 2.53	$ 2.44	$ 2.01	$ 1.98

The following table summarizes weighted-average fair value of options granted during the year:

	2001	2000	1999
PSP	$ -	$ 7.24	$ 3.89
DRP	$ 13.94	$ 6.98	$ 5.85
Total fair market of all options granted *(in thousands)*	$ 83	$15,054	$2,384

The fair value of each option grant is determined on the date of grant using the Black-Scholes option-pricing model with the following average assumptions:

	2001	2000	1999
Dividend yield	3.10%	2.98%	4.90%
Expected volatility	33.99%	26.43%	30.29%
Risk-free interest rates	5.38%	5.11%	6.43%
Expected life	10.0	10.0	10.0

Construction Program and Jointly-Owned Plants

The Company's construction expenditures for 2001 were approximately $264.9 million, including expenditures on jointly-owned projects. The Company's proportionate share of expenses for the jointly-owned plants is included in operating expenses in the consolidated statements of earnings.

At December 31, 2001, the Company's interests and investments in jointly-owned generating facilities are:

STATION (FUEL TYPE)	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	CONSTRUCTION WORK IN PROGRESS	COMPOSITE INTEREST
		(In thousands)		
San Juan Generating Station (Coal)	$709,699	$371,122	$ 2,180	46.3%
Palo Verde Nuclear Generating Station (Nuclear)*	$210,718	$ 59,932	$21,163	10.2%
Four Corners Power Plant Units 4 and 5 (Coal)	$118,497	$ 81,237	$ 3,187	13.0%

*Includes the Company's interest in PVNGS Unit 3, the Company's interest in common facilities for all PVNGS units and the Company's owned interests in PVNGS Units 1 and 2.

San Juan Generating Station ("SJGS")

The Company operates and jointly owns SJGS. At December 31, 2001, SJGS Units 1 and 2 are owned on a 50% shared basis with Tucson Electric Power Company, Unit 3 is owned 50% by the Company, 41.8% by Southern California Public Power Authority ("SCPPA") and 8.2% by Tri-State Generation and Transmission Association, Inc. Unit 4 is owned 38.457% by the Company, 28.8% by M-S-R Public Power Agency ("M-S-R"), 10.04% by the City of Anaheim, California, 8.475% by the City of Farmington, 7.2% by the County of Los Alamos, and 7.028% by Utah Associated Municipal Power Systems.

Palo Verde Nuclear Generating Station ("PVNGS")

PNM is a participant in the three 1,270 MW units of PVNGS, also known as the Arizona Nuclear Power Project, with Arizona Public Service Company ("APS") (the operating agent), Salt River Project, El Paso Electric Company ("El Paso"), Southern California Edison Company, SCPPA and The Department of Water and Power of the City of Los Angeles. PNM has a 10.2% undivided interest in PVNGS, with portions of its interests in Units 1 and 2 held under leases (see Commitments and Contingencies note for additional discussion).

Commitments and Contingencies

Long-Term Power Contracts

PNM has a power purchase contract with Southwestern Public Service Company ("SPS"), which originally provided for the purchase of up to 200 MW, expiring in May 2011. PNM may reduce its purchases from SPS by 25 MW annually upon three years' notice. PNM provided such notice to reduce the purchase by 25 MW in 1999 and by an additional 25 MW in 2000. PNM also is party to a master power purchase and sale agreement with SPS, dated August 2, 1999 pursuant to which PNM has agreed to purchase 72 MW of firm power from SPS from 2002 through 2005. PNM has 70 MW of contingent capacity obtained from El Paso under a transmission capacity for generation capacity trade arrangement through September 2004. Beginning October 2004 and continuing through June 2005, the capacity amount is 39 MW. PNM holds a PPA with Tri-State for 50 MW through June 30, 2010. In addition, PNM is interconnected with various utilities for economy interchanges and mutual assistance in emergencies.

In 1996, PNM entered into a long-term Power Purchase Agreement ("PPA") for the rights to all the output of a new gas-fired generating plant for 20 years. The PPA's maximum dependable capacity is 132 MW. In July 2000, the plant went into operation. The gas turbine generating unit is operated by Delta-Person Limited Partnership ("Delta") and is located on PNM's retired Person Generating Station site in Albuquerque, New Mexico. Primary fuel for the gas turbine generating unit is natural gas, which is provided by PNM. In addition, the unit has the capability to utilize low sulfur fuel oil in the event natural gas is not available or cost effective. For accounting purposes, the PPA is treated as an operating lease.

In July 2001, PNM entered into a long-term wholesale power contract with Texas-New Mexico Power ("TNMP") to provide power to serve TNMP's firm retail customers. The contract has a term of 5 1/2 years commencing July 1, 2001. PNM will provide varying amounts of firm power on demand to complement existing TNMP contracts. As those contracts expire, PNM will replace them and become TNMP's sole supplier beginning January 1, 2003. In the last year of the contract, it is estimated that TNMP will need 114 MW of firm power.

Coal Supply

The coal requirements for the SJGS are being supplied by San Juan Coal Company ("SJCC"), a wholly-owned subsidiary of BHP Holdings, who holds certain Federal, state and private coal leases under a Coal Sales Agreement, pursuant to which SJCC will supply processed coal for operation of the SJGS until 2017. BHP Minerals International, Inc. has guaranteed the obligations of SJCC under the agreement, which contemplates the delivery of approximately 103 million tons of coal during its remaining term. That amount would supply substantially all the requirements of the SJGS through approximately 2017.

Four Corners Power Plant ("Four Corners") is supplied with coal under a fuel agreement between the owners and BHP Navajo Coal Company ("BNCC"), under which BNCC agreed to supply all the coal requirements for the life of the plant. The current fuel agreement expires December 31, 2004. Negotiations for an extension have been initiated. BNCC holds a long-term coal mining lease, with options for renewal, from the Navajo Nation and operates a surface mine adjacent to Four Corners with the coal supply expected to be sufficient to supply the units for their estimated useful lives.

Natural Gas Supply

The Company contracts for the purchase of gas to serve its jurisdictional customers. These contracts are short-term in nature supplying the gas needs for the current heating season and the following off-season months. The price of gas is a pass-through, whereby the Company recovers 100% of its cost of gas.

The natural gas used as fuel by Generation and Trading was delivered by Gas. In the second quarter of 2001, the Company's Generation and Trading Operations began procuring its gas supply independent of the Company and contracting with the Utility Operations for transportation services only.

Construction Commitment

PNM has committed to purchase five combustion turbines at a total cost of $151.3 million. The turbines are for three planned power generation plants with a combined capacity of 657 MWs. The plants' estimated cost of construction is approximately $400.3 million. PNM has expended $103.4 million as of December 31, 2001. In November 2001, PNM broke ground for a new 135 MW single cycle gas turbine plant on a site in Southern New Mexico. This facility is expected to be operational by October 2002. Currently the Company plans to expand the facility to 225 MW by the end of 2003. In February 2002, PNM also broke ground for an 80 MW, natural gas fired generating plant in southwestern New Mexico. This facility is expected to be operational by July 2002. The planned plants are part of PNM's ongoing competitive strategy of increasing generation capacity over time. The costs of the plants are not anticipated to be added to the rate base.

PVNGS Liability and Insurance Matters

The PVNGS participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under Federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the primary liability insurance limit, the Company could be assessed retrospective adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88.1 million, subject to an annual limit of $10 million per reactor per incident. Based upon the Company's 10.2% interest in the three PVNGS units, the Company's maximum potential assessment per incident for all three units is approximately $27.0 million, with an annual payment limitation of $3 million per incident. If the funds provided by this retrospective assessment program prove to be insufficient, Congress could impose revenue raising measures on the nuclear industry to pay claims.

Aspects of the Federal law referred to above (the "Price-Anderson Act"), which provides for payment of public liability claims in case of a catastrophic accident involving a nuclear power plant are up for renewal in August 2002. While existing nuclear power plant would continue to be covered in any event, the renewal would extend coverage to future nuclear power plants and could contain amendments that would affect existing plants. A renewal bill was passed by the House with unanimous consent on November 27, 2001. The House proposed a change in the annual retrospective premium limit from $10 million to $15 million per reactor per incident. Additionally, the House proposed to amend the maximum potential assessment from $88.1 million to $98.7 million per reactor per incident, taking into account effects of inflation. On March 7, 2002 the Senate approved a Price-Anderson Act amendment as a part of the overall energy bill. The Senate version is substantially the same as the Price-Anderson Act in its current form. In the event the energy bill does not pass, it is possible that the Price-Anderson amendment would be passed as a stand-alone bill. In a report issued in 1998, the NRC had made a number of recommendations regarding the Price-Anderson Act, including a recommendation that Congress investigate whether the $200 million now available from the private insurance market for liability claims per reactor could be increased to keep pace with inflation. The Company cannot predict whether or not Congress will renew the Price-Anderson Act or act on the NRC's recommendation. However, if adopted, certain changes in the law could possibly trigger "Deemed Loss Events"under the Company's PVNGS leases, absent waiver by the lessors. Such an occurrence could require the Company to, among other things, (i) pay the lessor and the equity investor, in return for the investor's interest in PVNGS, cash in the amount as provided in the lease and (ii) assume debt obligations relating to the PVNGS lease (see Lease Commitment note).

The PVNGS participants maintain "all-risk"(including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.75 billion as of January 1, 2002, a substantial portion of which must be applied to stabilization and decontamination. The Company has also secured insurance against portions of the increased cost of generation or purchased power and business interruption resulting from certain accidental outages of any of the three units if the outages exceed 12 weeks. The insurance coverage discussed in this section is subject to certain policy conditions and exclusions. The Company is a member of an industry mutual insurer. This mutual insurer provides both the "all-risk"and increased cost of generation insurance to the Company. In the event of adverse losses experienced by this insurer, the Company is subject to an assessment. The Company's maximum share of any assessment is approximately $4.8 million per year.

PVNGS Decommissioning Funding

The Company has a program for funding its share of decommissioning costs for PVNGS. The nuclear decommissioning funding program is invested in equities and fixed income instruments in qualified and non-qualified trusts. The results of the 1998 decommissioning cost study indicated that the Company's share of the PVNGS decommissioning costs excluding spent fuel disposal will be approximately $181 million (in 1998 dollars).

The Company funded an additional $6.1 million, $3.9 million and $3.1 million in 2001, 2000 and 1999, respectively, into the qualified and non-qualified trust funds. The estimated market value of the trusts at the end of 2001 was approximately $57.3 million.

Nuclear Spent Fuel and Waste Disposal

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the United States Department of Energy ("DOE") is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. DOE has announced that such a repository now cannot be completed before 2010.

The operator of PVNGS has capacity in existing fuel storage pools at PVNGS which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of PVNGS through 2002, and believes it could augment that storage with the new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. The Company currently estimates that it will incur approximately $41.0 million (in 1998 dollars) over the life of PVNGS for its share of the fuel costs related to the on-site interim storage of spent nuclear fuel during the operating life of the plant. The Company accrues these costs as a component of fuel expense, meaning the charges are accrued as the fuel is burned. In 2001 and 2000, the Company expensed approximately $1.0 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned during 2001 and 2000. The operator of PVNGS currently believes that spent fuel storage or disposal methods will be available for use by PVNGS to allow its continued operation beyond 2002.

Natural Gas Explosion

On April 25, 2001, a natural gas explosion occurred in Santa Fe, New Mexico. The apparent cause of the explosion was a leak from a Company line near the location. The explosion destroyed a small building and injured two persons who were working in the building. The Company's investigation indicates that the leak was an isolated incident likely caused by a combination of corrosion and increased pressure. The Company also is cooperating with an investigation of the incident by the PRC's Pipeline Safety Bureau which issued its report on March 18, 2002. The Bureau's report gave PNM notice of 13 possible violations of the New Mexico Pipeline Safety Act and related regulations. Two lawsuits against the Company by the injured persons along with several claims for property and business interruption damages have been resolved by the Company. At this time, the Company is unable to estimate the potential liability, if any, that the Company may incur as a result of the Pipeline Safety Bureau's investigation. There can be no assurance that the outcome of this matter will not have a material adverse impact on the results of operations and financial position of the Company.

Western Resources Transaction

On November 9, 2000, the Company and Western Resources announced that both companies' Boards of Directors approved an agreement under which the Company will acquire the Western Resources electric utility operations in a tax-free, stock-for-stock transaction. The agreement required that Western Resources split-off its non-utility businesses to its shareholders prior to closing.

In July, 2001, the KCC issued two orders. The first order declared the split-off required by the agreement to be unlawful as designed, with or without a merger. The second order decreased rates for Western Resources, despite a request for $151 million increase. After rehearing the KCC established the rate decrease at $15.7 million. On October 3, 2001, the KCC issued an Order on Reconsideration reaffirming its decision that the split-off as designed in the agreement was unlawful with or without a merger.

Because of these rulings, the Company announced that it believed the agreement as originally structured could not be consummated. Efforts to renegotiate the transaction failed. Western Resources demanded that the Company file for regulatory approvals of the transaction as designed, despite the fact that the transaction required the split-off already determined to be unlawful by the KCC. As a result of the disagreement over the viability of the transaction as designed, the Company filed suit on October 12, 2001, in New York state court seeking declarations that the transaction could not be accomplished as designed due to the KCC's determination that the split-off condition of the transaction is unlawful; that the Company is not obligated to pursue approvals of the transaction as designed; that the transaction is terminated effective December 31, 2001, without an automatic extension; and that the KCC rate case order constitutes a material adverse effect under the agreement. The Company also seeks monetary damages for breach of contract because Western Resources represented and warranted that the split-off did not require approval of the KCC.

On November 19, 2001, Western Resources filed a complaint against the Company in New York state court alleging breach of contract and breach of implied covenant of good faith and fair dealing. Western Resources alleged that the Company brought about the KCC orders, failed to assist in efforts to reverse the KCC orders, refused to renegotiate within the terms of the agreement, interfered with Western Resources's efforts to satisfy the terms of the agreement, and effected an unauthorized de facto termination of the agreement by filing its complaint. Western Resources alleges damages in excess of $650 million. The Company believes that the complaint filed by Western Resources is without merit and intends to vigorously defend itself against the complaint. The Company also intends to vigorously pursue its own complaint.

On January 7, 2002, the Company notified Western Resources that it had taken action to terminate the agreement as of that date. The Company identified numerous breaches of the agreement by Western Resources and the regulatory rulings in Kansas as reasons for the termination. On January 9, 2002, Western Resources responded that it considered the Company's termination to be ineffective and the agreement to still be in effect.

On February 5, 2002, the District Court for Shawnee County, Kansas, dismissed without prejudice Western Resources' petition for judicial review of the KCC's split-off orders. The Court ruled that, by filing a new financial plan in compliance with the orders, Western Resources had accepted certain portions of the orders thereby creating a situation where further administrative action became necessary. As a result, the Court concluded that the matter was not ripe for judicial review and remanded the case to the KCC.

On March 8, 2002, the Kansas Court of Appeals affirmed the KCC's rate order.

The Company is currently unable to predict the outcome of its litigation with Western Resources.

Other

There are various claims and lawsuits pending against the Company and certain of its subsidiaries, in addition to the matters discussed above. The Company is also subject to Federal, state and local environmental laws and regulations, and is currently participating in the investigation and remediation of numerous sites. In addition, the Company periodically enters into financial commitments in connection with business operations. It is not possible at this time for the Company to determine fully the effect of all litigation on its consolidated financial statements. However, the Company has recorded a liability where the litigation effects can be estimated and where an outcome is considered probable. The Company does not expect that any known lawsuits, environmental costs and commitments will have a material adverse effect on its financial condition or results of operations.

Environmental Issues

The normal course of operations of the Company necessarily involves activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and in some instances may be imposed without regard to fault, or may be imposed for past acts, even though the past acts may have been lawful at the time they occurred. Sources of potential environmental liabilities include the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980 and other similar statutes.

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, the Company records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

The Company's recorded estimated minimum liability to remediate its identified sites is $6.8 million. The ultimate cost to clean up the Company's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; and the time periods over which site remediation is expected to occur. The Company believes that, due to these uncertainties, it is remotely possible that cleanup costs could exceed its recorded liability by up to $11.6 million. The upper limit of this range of costs was estimated using assumptions least favorable to the Company.

For the year ended December 31, 2001, 2000 and 1999, the Company spent $1.7 million, $1.6 million and $4.4 million, respectively, for remediation. The majority of the December 31, 2001, environmental liability is expected to be paid over the next five years, funded by cash generated from operations. Future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company.

New and Proposed Accounting Standards

Statement of Financial Accounting Standards, No. 143. *"Accounting for Asset Retirement Obligations"* ("SFAS 143"). In June 2001, the FASB issued SFAS 143. The statement requires the recognition of a liability for legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction or development and/or the normal operation of a long-lived asset. The asset retirement obligation is required to be recognized at its fair value when incurred. The cost of the asset retirement obligation is required to be capitalized by increasing the carrying amount of the related long-lived asset by the same amount as the liability. This cost must be expensed using a systematic and rational method over the related asset's useful life. SFAS 143 is effective for the Company beginning January 1, 2003. The Company is currently assessing the impact of SFAS 143 and is unable to predict its impact on the Company's operating results and financial position at this time.

Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* ("SFAS 144"). In August 2001, the FASB issued SFAS 144. The statement amends certain requirements of the previously issued pronouncement on asset impairment, SFAS 121. SFAS 144 removes goodwill from the scope of SFAS 121, provides for a probability-weighted cash flow estimation approach for estimating possible future cash flows, and establishes a "primary asset"approach for a group of assets and liabilities that represents the unit of accounting to be evaluated for impairment. In addition, SFAS 144 changes the measurement of long-lived assets to be disposed of by sale, as accounted for by *"Accounting Principles Board Opinion No. 30"*. Under SFAS 144, discontinued operations are no longer measured on a net realizable value basis, and their future operating losses are no longer recognized before they occur. The Company does not believe SFAS 144 will have a material effect on its future operating results or financial position.

quarterly operating results

The unaudited operating results by quarters for 2001 and 2000 are as follows:

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
	(In thousands, except per share amounts)			
2001:				
Operating Revenues	$ 736,530	$ 666,091	$ 621,895	$ 327,581
Operating Income	77,300	80,547	47,422	17,407
Earnings from Continuing Operations	63,552	49,597	32,775	4,509
Net Earnings	63,552	49,597	32,775	4,509
Net Earnings per share from Continuing Operations	1.62	1.26	0.83	0.11
Net Earnings per Share (Basic)	1.62	1.26	0.83	0.11
Net Earnings per Share (Diluted)	1.60	1.24	0.82	0.11
2000:				
Operating Revenues	$ 321,291	$ 329,041	$ 499,477	$ 461,465
Operating Income	30,947	27,654	47,452	26,422
Earnings from Continuing Operations	21,952	17,986	46,913	14,096
Net Earnings	21,952	17,986	46,913	14,096
Net Earnings per share from Continuing Operations	0.55	0.45	1.19	0.36
Net Earnings per Share (Basic)	0.55	0.45	1.19	0.36
Net Earnings per Share (Diluted)	0.55	0.45	1.18	0.35

In the opinion of management of the Company, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of the results of operations for such periods have been included.

comparative operating statistics
(unaudited)

	2001	2000	1999	1998	1997
Utility Operations Sales:					
Energy Sales--KWh (in thousands):					
Residential	2,197,889	2,171,945	2,027,589	2,022,598	1,951,219
Commercial	3,213,208	3,133,996	2,981,656	2,909,752	2,805,576
Industrial	1,603,266	1,544,367	1,559,155	1,571,824	1,556,264
Other ultimate customers	240,934	238,635	235,183	235,700	221,840
Total KWh sales	7,255,297	7,088,943	6,803,583	6,739,874	6,534,899
Gas Throughput—Decatherms (in thousands):					
Residential	27,848	28,810	32,121	29,258	30,605
Commercial	10,421	9,859	11,106	10,044	10,592
Industrial	3,920	5,038	2,338	1,553	1,280
Other	4,355	6,426	6,538	8,390	8,158
Total gas sales	46,544	50,133	52,103	49,245	50,635
Transportation throughput	51,395	44,871	40,161	36,413	33,975
Total gas throughput	97,939	95,004	92,264	85,658	84,610
Revenues (in thousands):					
Electric Revenues:					
Residential	$ 187,600	$ 186,133	$ 184,088	$ 187,681	$ 184,813
Commercial	242,372	238,243	238,830	241,968	237,629
Industrial	82,752	79,671	85,828	88,644	86,927
Other ultimate customers	14,795	14,618	13,777	18,124	10,135
Total revenues to ultimate customers	527,519	518,665	522,523	536,417	519,504
Intersegment revenues	707	707	707	707	-
Miscellaneous electric revenues	31,707	20,093	18,345	19,151	3,331
Total electric revenues	$ 559,933	$ 539,465	$ 541,575	$ 556,275	$ 522,835
Gas Revenues:					
Residential	$ 232,321	$ 191,231	$ 152,266	$ 160,398	$ 185,851
Commercial	68,895	52,964	37,337	42,480	50,042
Industrial	27,519	24,206	8,550	4,887	4,533
Other	28,896	29,203	20,080	27,218	30,285
Revenues from gas sales	357,631	297,604	218,233	234,983	270,711
Transportation	20,188	14,163	12,390	13,464	14,172
Other	7,599	8,157	6,088	7,528	9,886
Total gas revenues	$ 385,418	$ 319,924	$ 236,711	$ 255,975	$ 294,769
Total Utility Revenues	$ 945,351	$ 859,389	$ 778,286	$ 812,250	$ 817,604

(Continued on page 86)

comparative operating statistics
(unaudited)

(Continued from page 85)

	2001	2000	1999	1998	1997
Customers at Year End:					
Electric:					
Residential	336,614	328,519	321,949	319,415	311,314
Commercial	39,674	38,991	38,435	37,652	36,942
Industrial	377	371	375	363	363
Other ultimate customers	924	625	625	665	637
Total ultimate customers	377,589	368,506	361,384	358,095	349,256
Sales for Resale	79	81	83	83	66
Total customers	377,668	368,587	361,467	358,178	349,322
Gas:					
Residential	404,753	398,623	390,428	383,292	375,032
Commercial	32,894	32,626	32,116	32,004	31,560
Industrial	50	50	51	55	50
Other	3,528	3,612	3,688	3,622	3,765
Transportation	34	32	32	29	31
Total customers	441,259	434,943	426,315	419,002	410,438

comparative operating statistics (unaudited)

	2001	2000	1999	1998	1997
Generation and Trading Operations Sales:					
Energy Sales—KWh (in thousands):					
Firm-requirements wholesale	616,703	330,003	179,249	278,615	278,727
Other contracted off-system	6,900,589	7,315,679	6,196,499	4,033,931	3,790,081
Economy energy sales	5,059,808	4,706,446	4,795,873	4,469,769	2,716,835
Total sales to ultimate customers	12,577,100	12,352,128	11,171,621	8,782,315	6,785,643
Intersegment sales	7,255,297	7,088,943	6,803,583	6,739,874	6,534,899
Total energy sales	19,832,397	19,441,071	17,975,204	15,522,189	13,320,542
Revenues (in thousands):					
Firm-requirements wholesale	$ 24,754	$ 15,540	$ 7,046	$ 10,708	$ 10,690
Other contracted off-system	892,105	364,278	226,773	142,115	118,876
Economy energy sales	512,209	368,374	131,549	122,156	55,768
Total revenues to ultimate customers	1,429,068	748,192	365,368	274,979	185,334
Intersegment revenues	341,608	324,744	318,872	362,722	370,019
Miscellaneous electric revenues	(23,152)	2,242	5,741	4,657	14,269
Total generation revenues	$1,747,524	$1,075,178	$ 689,981	$ 642,358	$ 569,622
Customers at Year End:					
Generation	79	81	83	83	66
Reliable Net Capability—KW	1,521,000	1,521,000	1,521,000	1,506,000	1,506,000
Coincidental Peak Demand—KW	1,397,000	1,368,000	1,291,000	1,313,000	1,209,000
Average Fuel Cost per Million BTU	$ 1.6007	$ 1.3827	$ 1.3169	$ 1.2433	$ 1.2319
BTU per KWh of Net Generation	10,549	10,547	10,490	10,784	10,927

shareholders information

Annual Stockholders' Meeting

The 2002 Annual Meeting of Stockholders will be held at 9:30 AM on May 14, 2002 at: The South Broadway Cultural Center, 1025 Broadway SE, Albuquerque, NM. Proxies will be requested from stockholders when the notice of meeting and proxy statement are mailed on or about April 10.

Stock Listing

The Common Stock is listed on the New York Stock Exchange. The Common Stock ticker symbol is "PNM." The press listing is PNM Res. As of December 31, 2001, there were 15,377 common shareholders of record.

Transfer Agent and Registrar

PNM Resources Shareholder Records Department, Alvarado Square, Mail Stop 1104, Albuquerque, NM 87158, Telephone (toll-free): 800-545-4425, Fax: 505-241-4311, E-Mail: yjohnso@pnm.com

Dividend Reinvestment and Direct Stock Purchase Plan

PNM Resources offers a dividend reinvestment and direct stock purchase plan as a service to all interested participants. In addition to full or partial reinvestment of dividends, the PNM Direct Plan gives shareholders the opportunity to make direct cash investments ranging from $50 to $5,000 as often as once a month. Information regarding the Plan can be obtained by calling Shareholder Records at 800-545-4425.

Additional Information

The Company reports details concerning its operations and other matters annually to the Securities and Exchange Commission on Form 10-K, which is available without charge to the Company's security holders, upon written request to the Senior Vice President of Communications, Investor Services and Community Relations.

A supplement containing additional financial and operating data for the latest 10-year period may be obtained by writing to the Senior Vice President of Communications, Investor Services and Community Relations.

For up-to-date stock quotes, quarterly earnings results and other important information, visit the PNM web site at pnm.com.

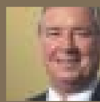
Contact Information

CORPORATE HEADQUARTERS: PNM Resources, Inc., Alvarado Square, Albuquerque, NM 87158, 505-241-2700
INVESTOR RELATIONS: Barbara L. Barsky, Senior Vice President, Communications, Investor Services and Community Relations, Telephone: 505-241-2662; Fax: 505-241-2368; E-Mail: bbarsky@pnm.com
NEW MEXICO UTILITY SHAREHOLDERS ALLIANCE: P.O. Box 728, Albuquerque, NM 87103

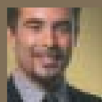
COMMON STOCK PRICES AND DIVIDENDS PAID: *(in dollars)*

	2001			2000		
QUARTER	DIVIDEND	HIGH	LOW	DIVIDEND	HIGH	LOW
1	$0.20	$29.340	$22.875	$0.20	$16.875	$14.625
2	$0.20	$37.800	$28.700	$0.20	$18.000	$15.313
3	$0.20	$33.550	$24.720	$0.20	$26.440	$15.375
4	$0.20	$28.680	$24.350	$0.20	$28.313	$20.750

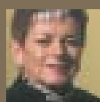
board of directors of PNM Resources



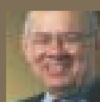
ROBERT G. ARMSTRONG ◆ ✣
President of Armstrong Energy Corporation, Age 55, Director since 1991



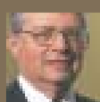
R. MARTIN CHAVEZ, PH.D. ◆ ✹
Chairman and Chief Executive Officer of Kiodex, Inc., Age 38, Director since 2001



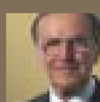
JOYCE A. GODWIN ✲ ✣
Retired President and Secretary of Presbyterian Healthcare Services, Age 58, Director since 1989



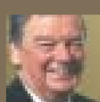
BENJAMIN F. MONTOYA ✹
Retired Chairman, President and Chief Executive Officer of PNM, Age 66, Director since 1993



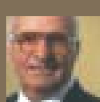
MANUEL T. PACHECO, PH.D. ◆ ✣
President, University of Missouri System, Age 60, Director since 2001



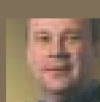
THEODORE F. PATLOVICH ✲ ✹
Retired Vice Chairman and Senior VP Of Loctite Corporation, Age 75, Director since 2000



ROBERT M. PRICE ✲ ✹
President of PSV, Inc. a technology consulting business, Age 71, Director since 1992



PAUL F. ROTH ✲ ✣
Retired President of the Texas Division of Southwestern Bell Telephone Company, Age 69, Director since 1991



JEFFRY E. STERBA
Chairman, President and Chief Executive Officer of PNM Resources, Inc., Age 46, Director since 2000

◆ Audit Committee and Ethics Committee
✣ Customer Policy Committee
✹ Finance Committee
✲ Board Governance and Human Resources Committee

Effective as of 3/25/02

officers of PNM Resources

*JEFFRY E. STERBA, 46
Chairman, President and Chief Executive Officer

*ROGER J. FLYNN, 59
Executive VP, Electric and Gas Services

*WILLIAM J. REAL, 53
Executive VP, Power Production and Marketing

*BARBARA L. BARSKY, 57
Senior VP, Communications, Investor Services, and Community Relations

*ALICE A. COBB, 44
Senior VP, People Services and Development

*MAX H. MAERKI, 62
Senior VP and Chief Financial Officer

PATRICK T. ORTIZ, 52
Senior VP, General Counsel and Secretary

*EDDIE PADILLA, JR., 48
Senior VP, Bulk Power Marketing and Development

*R. BLAKE RIDGEWAY, 43
Senior VP, Energy Services

ERNEST T. C'DE BACA, 48
VP, Governmental Affairs

TERRY R. HORN, 49
VP and Treasurer

JOHN R. LOYACK, 38
VP, Corporate Controller and Chief Accounting Officer

* Board of Directors of PNM

officers of PNM

MELVIN J. CHRISTOPHER, 41
VP, Operations and Engineering

PATRICK J. GOODMAN, 52
VP, Generation Construction and Operations

SARITA P. LOEHR, 45
VP, Customer Service

CINDY E. MCGILL, 45
VP, Regulatory Policy and Public Policy

JOHN H. MYERS, 44
VP, Construction and Reliability

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WE HAVE THE POWER

PNM RESOURCES

2001 ANNUAL REPORT

PNM Resources

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