THIS WAS A YEAR THAT MANY COMPANIES DECIDED TO GO BACK TO THE BASICS. FORTUNATELY, WE NEVER LEFT.

2002
ANNUAL REPORT

PNM is built on the basics: integrity and fairness in all our dealings with people; responsible stewardship for our environment and the natural resources we use, the communities we serve, and the corporate assets we manage; engagement in making a difference through innovation, creativity, service and teamwork. Our strategic plan is straightforward. Our philosophy is simple: delivering value to customers builds value for shareholders.

FELLOW SHAREHOLDERS

letter to SHAREHOLDERS

While 2002 was the most turbulent year in the energy industry's history, PNM Resources succeeded in laying a strong foundation for future growth, both in our core electric and gas utility and in our wholesale power marketing business.

We negotiated an agreement setting PNM retail electric rates in New Mexico for the next five years. This agreement provides PNM with a predictable revenue stream and allows us to efficiently combine all of our generating resources to serve both retail and wholesale customers. If New Mexico decides to continue the existing system of public utility regulation, PNM will remain the sole supplier of electricity in our home territory.

We expect the reduced revenues under the new, lower electric rates to be offset by lower fuel costs at our San Juan Generating Station. The shift from a surface to an underground mine is now complete, giving us access to a higher quality coal at lower cost. Since the plant burns more than 6 million tons of coal a year, these savings should be substantial over the life of the mine.

With new electric rates in place, we are now taking steps to improve the rate of return in our gas utility. I know that no one, including me, likes to pay more for anything. But we need the opportunity to earn an appropriate return on our gas business. In January 2003, PNM filed a request for a $37.6 million increase in the fees we charge customers for natural gas service. If approved by regulators, that increase will take effect at the end of 2003.

We expect that earnings growth on the utility side of our business will flow from the continued economic growth in New Mexico and from the cost reductions achieved by making our operations more efficient and productive.

Despite weakness in the national economy, PNM retail electric revenues rose nearly 2 percent in 2002. The growth in our local service territory has exceeded the national average in each of the last 10 years, and we expect this pattern will continue in 2003 and beyond.

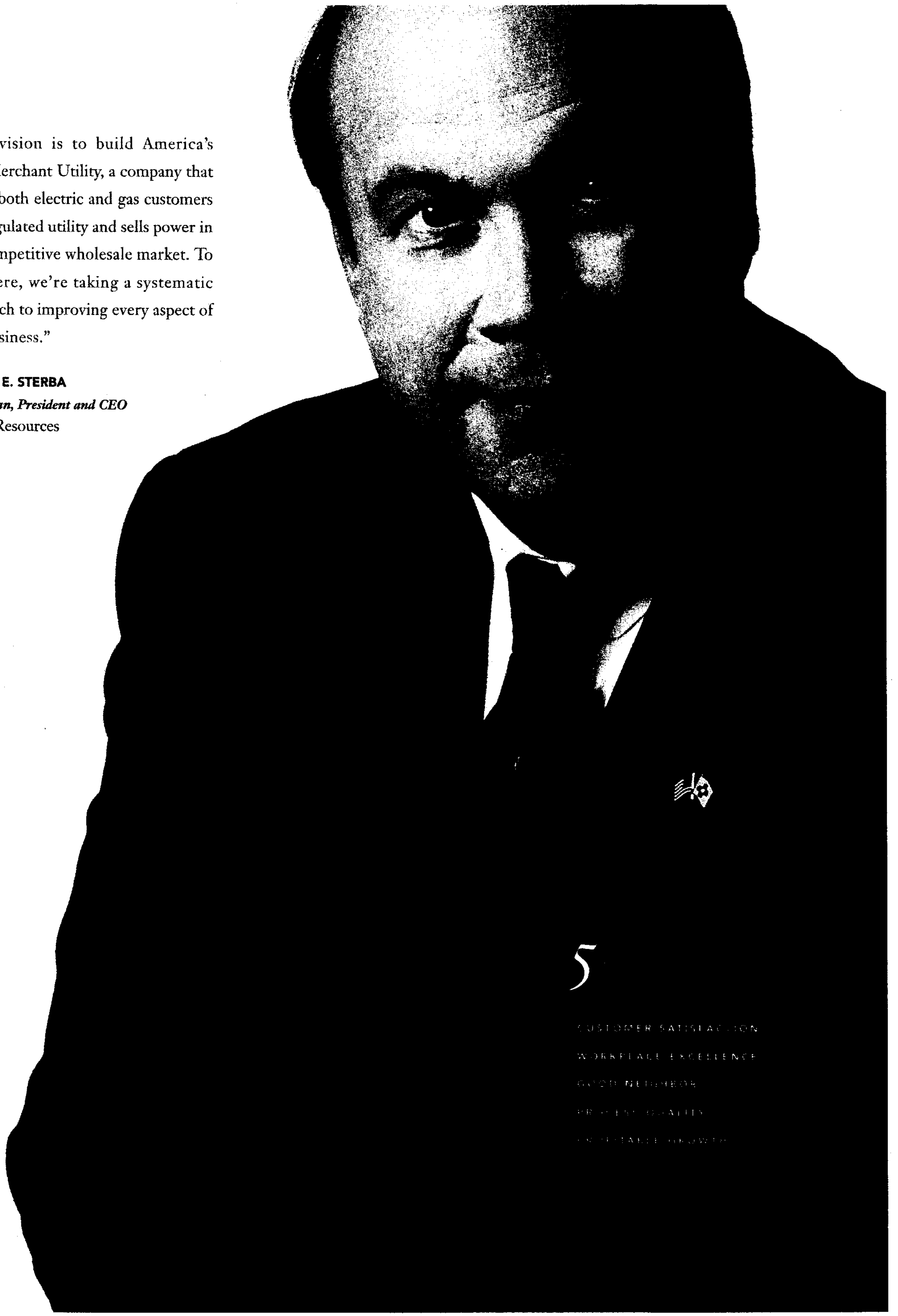
A ROCKY YEAR IN THE WHOLESALE MARKET

In sharp contrast to the growth in our utility business, PNM wholesale power revenues plunged more than 60 percent in 2002. Because of low prices and slack activity in that market, the wholesale power business contributed just 28 percent of total operating revenues in 2002, compared to about 60 percent in 2001.

Painful as it has been, I believe this steep downturn will ultimately benefit both PNM and the market as a whole. What we saw in 2002 was the necessary correction to the excesses bred by the temporary bubble in 2001. Today, wholesale prices and activity remain depressed as the industry slowly absorbs all the new generating capacity added over the last two years. But as supply and demand come back into balance, the wholesale power market can return to what it should have been all along: an efficient means of matching sellers and buyers to the benefit of both.

"Our vision is to build America's Best Merchant Utility, a company that serves both electric and gas customers as a regulated utility and sells power in the competitive wholesale market. To get there, we're taking a systematic approach to improving every aspect of our business."

JEFFRY E. STERBA
Chairman, President and CEO
PNM Resources



Two-thousand six hundred employees, one shared vision: Build America's Best Merchant Utility. In 2002 we made measurable progress toward that goal.

THERE IS POWER IN NUMBERS

In that revived market, PNM will be well positioned to build on our past success. For more than a decade, our strategy has focused not on short-term ups and downs in the market but on building long-term, stable relationships by meeting the needs of smaller utilities and other customers.

For example, at the end of 2002 PNM agreed to provide 80 megawatts of power to the U.S. Navy in San Diego, California. This contract, which will bring us $42 million in annual revenues, represents the kind of solid base we are building in our wholesale business. Including our obligation to serve retail customers in New Mexico, about three quarters of PNM generating capacity is now committed under long term agreements.

ADDING GENERATION RESOURCES

Our continued participation in the wholesale power market, together with growth in our home territory, requires us to invest in serving those new customers.

One of my personal highlights in 2002 came on a trip to a West Texas "wind farm," where we climbed a ladder 210 feet into the air to inspect a generating turbine attached to three giant blades. That visit was in preparation for announcing PNM's commitment to the New Mexico Wind Energy Center. When it's operational later this year, this wind farm will be one of the largest such projects in the nation, with 136 turbines generating 200 megawatts of electricity – enough power to supply nearly 100,000 homes in the Southwest.

PNM has agreed to buy all that power under a long-term contract. The wind farm will be a competitively priced source of clean, renewable energy both for our retail customers and for PNM wholesale customers throughout the region. While coal, natural gas and nuclear energy will continue to supply the majority of PNM's power for years to come, this project represents a historic step forward in reducing our reliance on fossil fuel generation. This positions our company as a leader in the move toward "green energy."

Our wind energy commitment was just one of three additions to the PNM generating portfolio in 2002. The other two are clean burning natural gas-fired power plants in southern New Mexico. Together they produce about 221 megawatts, increasing PNM net generating capacity by about 13 percent.

IN RELI

56

In [illegible], PNM customers experienced, on average, just 56 minutes of power outages – less than an hour out of 8,760 hours during the course of the year, and 8 1/2 minutes less than the previous year.

26

The average time it takes for a customer to reach a Customer Care Representative in the PNM call center. In one study of utilities nationwide, PNM ranked number one in call-in satisfaction and in the top three among all companies surveyed for overall customer satisfaction.

1

In a 2001 [illegible] PNM [illegible] system [illegible]

RECOGNIZE GOOD IDEAS, IMPLEMENT GR

letter to SHAREHOLDERS (continued)

HONESTY, INTEGRITY AND SOUND BUSINESS PRACTICES

Discussing the wholesale energy market brings up a painful subject: the scandals that have undermined investor confidence in corporate America over the past year. I want to assure you that PNM Resources did not engage in any of the misconduct that has recently tarnished our industry's reputation. In fact, most of the reforms now being adopted by others have long been standard practice for your company. Our "Do the Right Thing" business ethics program, for instance, has been in place since 1995 and has been updated several times since then. All employees engage in refresher training to make sure that our dealings with customers, co-workers, business partners and shareholders are above reproach.

We have equally high standards in corporate governance. Your Board of Directors is actively involved in setting strategic direction and holding management accountable for our performance. Except for myself the board is made up entirely of independent directors. Their combined wealth of industry expertise, broad experience and sound business judgment is an invaluable resource for our company. All of us share an unwavering commitment to serving the best interests of shareholders.

You'll find more details about the PNM Resources Board, including a description of the key committees that oversee our accounting practices, disclosure standards and executive compensation, in the 2003 proxy statement.

CONTINUOUS IMPROVEMENT TOWARD A BOLD GOAL

Our vision is to build America's Best Merchant Utility, a company that serves both electric and gas customers as a regulated utility and sells power in the competitive wholesale market. To get there, we're taking a systematic approach to improving every aspect of our business.

We have established a set of high-level goals in customer satisfaction, workplace excellence, process improvement, being a good neighbor and driving profitable growth. Each of these goals aims to deliver improved value to our key stakeholders. Performance measures built around each goal help us find and close the gaps between where we are and where we want to be. Through this process we engage everyone in the company, from top executives to front-line workers, in aligning their personal efforts with the goals we have all agreed on.

"We're building homes today that are more energy efficient, more comfortable, more affordable and healthier than was possible 10-15 years ago. With the special meters PNM has installed in 30 of our new homes, we're learning more and more about how to build a better home."

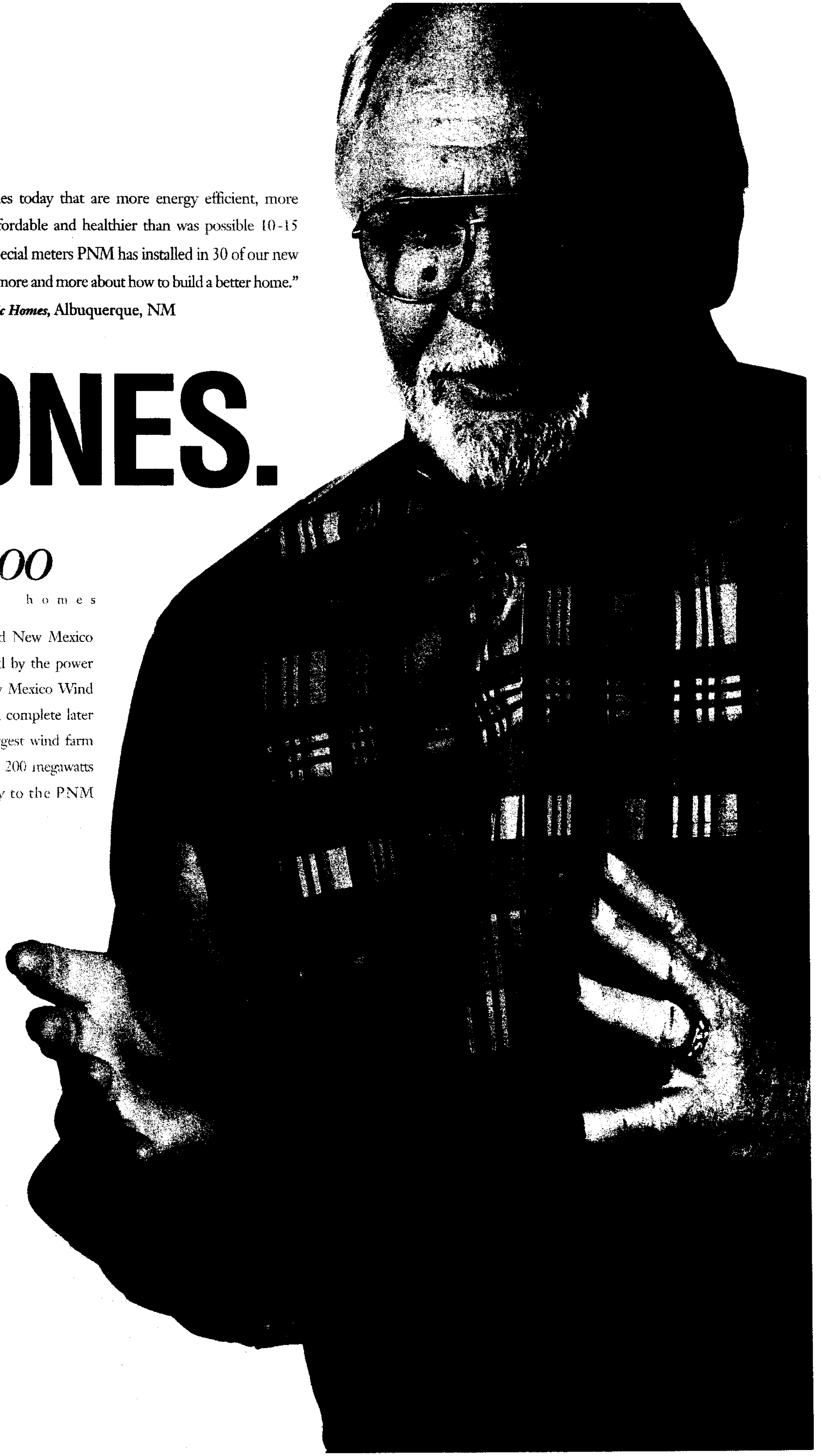
JERRY WADE - ***Artistic Homes,*** Albuquerque, NM

EAT ONES.

97,000

homes

Ninety-seven thousand New Mexico homes could be served by the power generated by the New Mexico Wind Energy Center. When complete later this year, the third largest wind farm in the nation will add 200 megawatts of renewable energy to the PNM generation portfolio.



PROTECTING THE EARTH IS NOT JUST A JOB.

83%

IT'S A PRIVILEGE.

For instance, identifying and improving the processes in our customer service call center has allowed us to cut the average time a customer waits on hold to just 26 seconds. That's one of the reasons a 2002 national survey ranked PNM first among the utilities surveyed in customer call satisfaction. The same systematic approach has helped us reduce the number and length of outages. In another survey last year, your company ranked number one in the nation for system reliability.

We measure ourselves against the industry's top performers because our goal is to be an industry leader. We want to rank number one. This is what we mean by America's "best" merchant utility. Continual improvement is making us more flexible in adapting to change, more responsive to customers and more tightly focused on transforming customer needs into shareholder value.

PNM is building nesting platforms and perches, installing safety devices throughout our system and working with wildlife preservation groups to help safeguard New Mexico habitat. Kree, a Swainson's Hawk, is part of a HawkWatch program that uses birds not suitable for rehabilitation in the wild to teach school children about raptors.

47%

Forty-seven percent of the developers who rely on us to install new electric and gas service say they were completely satisfied with PNM last year - more than double the number who gave us the highest grade three years ago. We've streamlined the process and made it easier for the customer by providing 'one stop shopping' for utility, phone and cable TV hookup.

PROCESS MATTERS.

letter to
SHAREHOLDERS
(continued)

OUR COMMITMENT TO YOU

Your company earned $1.61 per diluted share in 2002, down from $3.77 per share in 2001, primarily due to lower prices and reduced activity in the wholesale power market. Including the 86 cents per share paid in common stock dividends, total return on PNM Resources stock was a negative 11.7 percent in 2002.

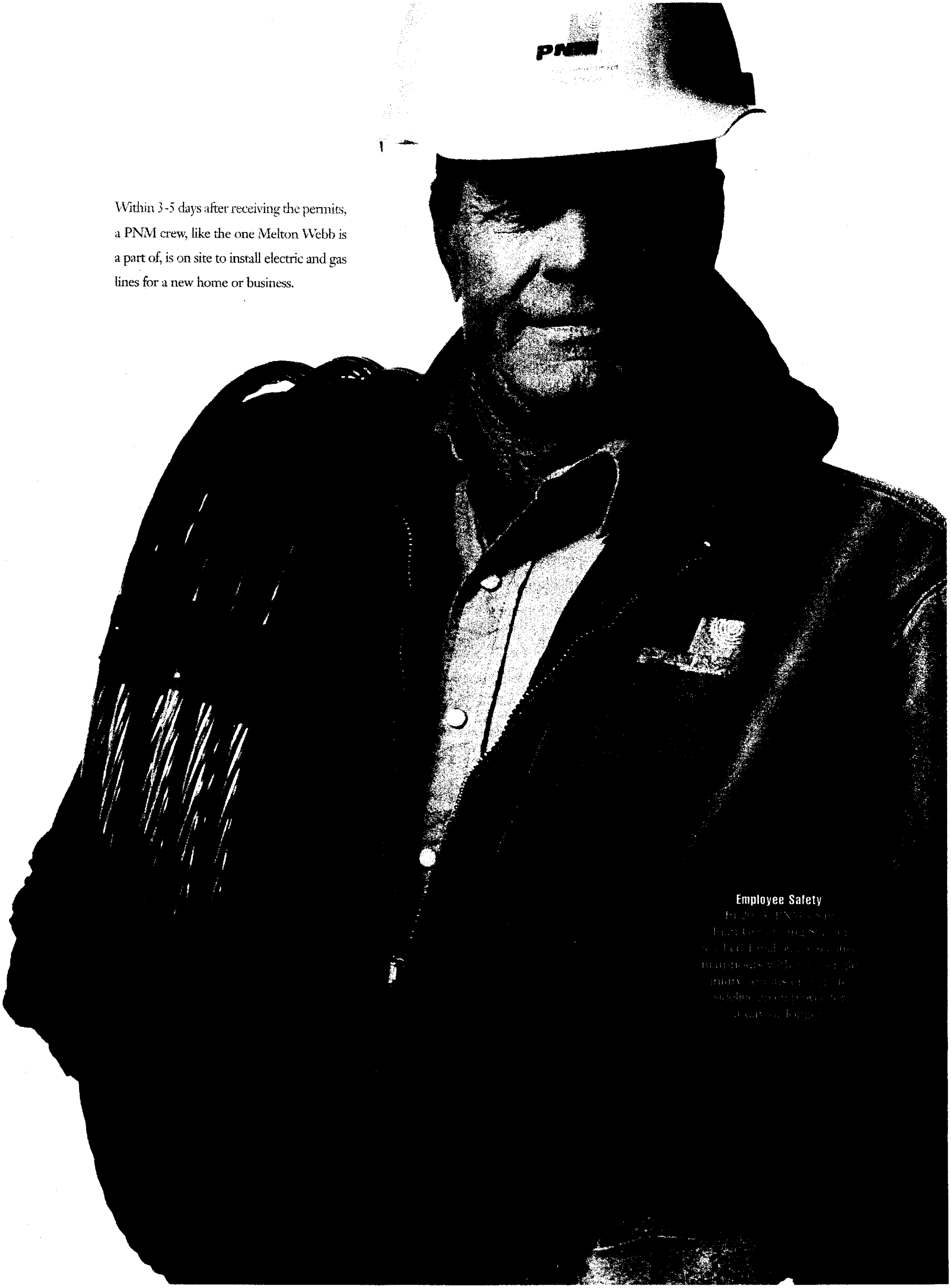
By comparison, the stocks in the S&P 500 index posted a negative 22.1 percent total return in 2002, while the stocks in a peer group of electric and gas utilities posted a negative 18.0 percent total return. Over the past three years, PNM total return has been +60.9 percent compared to -37.4 percent for the S&P 500 and +13.8 percent for our peer group.

I believe our performance relative to our peers says something about the folks who run your company. We're conservative, we're cautious.

As a result, PNM Resources today has a continuing strong cash flow and a healthy financial position. At the end of 2002, your company not only renewed but expanded our line of credit, adding four new banks to the pool of participants and increasing the company's borrowing limit from $150 million to $195 million. We are committed to maintaining our investment grade credit rating in 2003.

In a challenging year, your company emerged more efficient and productive and financially stronger than many other companies in our industry. In February 2003, at a time when some other utilities were being forced to reduce or even eliminate their dividend to shareholders, we were able to increase the PNM Resources dividend by 4.5 percent, to an annual rate of 92 cents per share.

Within 3-5 days after receiving the permits, a PNM crew, like the one Melton Webb is a part of, is on site to install electric and gas lines for a new home or business.



Employee Safety

[illegible]

Last year we rolled out a new ad campaign, "A Personal Commitment to New Mexico," with commercials, billboards and print ads featuring not actors but real PNM workers. I was pleased and proud to see the way that slogan was so enthusiastically adopted by everyone in our organization. The message strikes a chord with our employees as a natural expression of what they do every day in providing reliable and affordable energy services.

It's that level of commitment that gives me confidence in the future of PNM Resources. Our commitment is not just to customers, to employees and to the communities we serve, but to the shareholders whose investment has made our company what it is today.

We have many things on our table to manage in 2003. But in closing let me list our five top priorities for the year:

- Continue progress toward our performance objectives;
- Achieve an acceptable return on our gas business through a successful outcome from the pending rate case;
- Continue our incremental expansion in the wholesale electricity market by making additional long-term sales;
- Expand our efforts in environmental stewardship through renewable energy and our company-wide emphasis on environmental awareness; and
- Pursue new growth opportunities as our marketplace changes.

We will demonstrate our commitment to shareholder value by continuing to improve our balance sheet strength, provide a secure dividend, and find ways to provide earnings growth over the next few years.

It is a pleasure to lead your company forward into 2003.

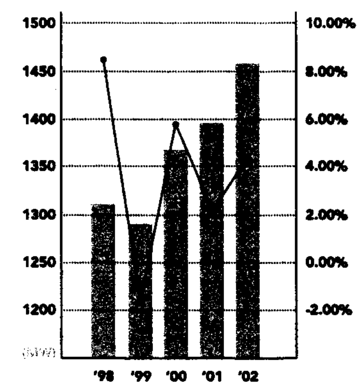
Sincerely,

Jeffry E. Sterba
Chairman, President and CEO

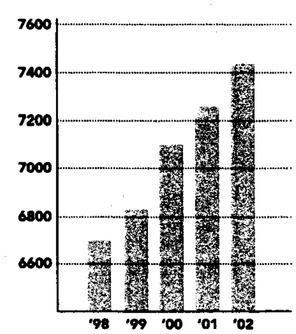
The underlying growth rate in our home service territory has exceeded the national average for most of the past decade.

PNM peak electric load in the summer of 2002 rose 4 percent to 1456

READY PLAN GROW.



5-YEAR SYSTEM PEAK DEMAND
(for retail and firm requirement customers)



RETAIL ELECTRIC SALES
(total MWh in thousands)

megawatts

SEEK KNOWLEDGE, TRUST

As a director of PNM Resources, I'm accountable to the company's stakeholders. I in turn hold management accountable as we safely guide the company through these tumultuous times.

R. MARTIN CHAVEZ, Ph.D
CHAIRMAN AND
CHIEF EXECUTIVE OFFICER
Kiodex, Incorporated
Corporate risk management and financial reporting

Age 39
Director since [illegible]

committees
Finance
Audit and Ethics

PNM put its own house in order in the early 1990s, implementing many of the best practices in corporate governance now being adopted by others. As a result, the PNM Resources board has been able to focus on increasing shareholder value in today's challenging environment.

JOYCE A. GODWIN
RETIRED VICE PRESIDENT
AND SECRETARY
Presbyterian Healthcare Services
Age [illegible]
Director since 1989

committees
Customer Policy – *Chair*
Board Governance and Human Resources

EXPERIENCE.
APPLY WISDOM.

The events of the past year have strengthened my commitment to providing my independent strategic experience in assisting PNM Resources to satisfy the interests of all of our stakeholders, and support our company's ongoing intrinsic value.

THEODORE F. PATLOVICH

Retired Vice Chairman and SEP
Loctite Corporation
Age 75
Director since 2000

committees

Board Governance and Human Resources
Finance

[illegible] of corporate excellence to which PNM Resources and the board are committed.

ROBERT M. PRICE

President
PSV, Inc.
A Technology Consulting Firm
Age 71
Director since 1992

committees

Board Governance and Human Resources – Chair
Finance

As one of the newest members of the PNM Resources Board, I was impressed with the rigorous selection process for directors. The commitment to diversity and the emphasis on bringing in outside knowledge and broad expertise signals a board and company desiring growth and excellence to best serve the shareholders.

BONNIE S. REITZ

Senior Vice President, Sales and Distribution
Continental Airlines
Age 50
Director since 2002

committees

Board Governance and Human Resources
Customer Policy

[illegible]

committees

Board Governance
and Human Resources
Finance

All of us share an unwavering commitment to serving the best interests of shareholders.

JEFFRY E. STERBA

Chairman, President and Chief Executive Officer
PNM Resources, Inc.
Age 47
Director since 2000

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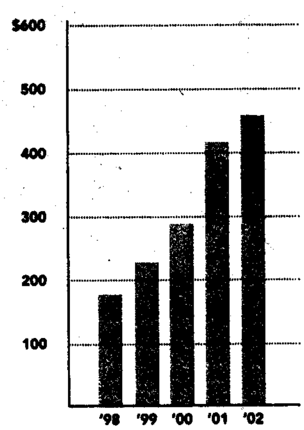
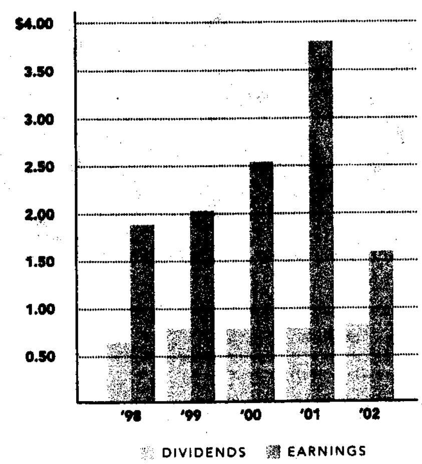
FINANCIAL INFORMATION



FINANCIAL STRENGTH
(retained earnings in millions)



EARNINGS & DIVIDENDS PAID
(per share of common stock, diluted)

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 "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.

	2002	2001	2000	1999	1998
	(In thousands except per share amounts and ratios)				
Total Operating Revenues	$1,168,996	$ 2,339,817	$1,611,274	$1,157,543	$1,092,445
Earnings from Continuing Operations	$ 64,272	$ 150,433	$ 100,946	$ 79,614	$ 95,119
Net Earnings	$ 64,272	$ 150,433	$ 100,946	$ 83,155	$ 82,682
Earnings per Common Share:					
Continuing Operations	$ 1.63	$ 3.83	$ 2.54	$ 1.93	$ 2.27
Basic	$ 1.63	$ 3.83	$ 2.54	$ 2.01	$ 1.97
Diluted	$ 1.61	$ 3.77	$ 2.53	$ 2.01	$ 1.95
Cash Flow Data:					
Net cash flows provided from operating activities	$ 97,251	$ 327,346	$ 239,515	$ 213,045	$ 210,988
Net cash flows used in investing activities	$ (200,427)	$ (407,014)	$ (157,500)	$ (55,886)	$ (340,992)
Net cash flows generated (used) by financing activities	$ 78,470	$ 385	$ (94,723)	$ (98,040)	$ 173,089
Total Assets	$3,026,907	$2,913,788	$2,889,917	$2,723,268	$2,668,603
Long-Term Debt, including current maturities	$ 980,092	$ 953,884	$ 953,823	$ 988,489	$1,008,614
Common Stock Data:					
Market price per common share at year end	$ 23.820	$ 27.950	$ 26.813	$ 16.250	$ 20.438
Book value per common share at year end	$ 24.90	$ 25.87	$ 23.42	$ 21.79	$ 20.63
Average number of common shares outstanding	39,118	39,118	39,487	41,038	41,774
Cash dividend declared per common share	$ 0.88	$ 0.80	$ 0.80	$ 1.00	$ 0.60
Return on Average Common Equity	6.2%	14.8%	11.1%	9.5%	9.9%
Capitalization:					
Common stock equity	49.2%	50.8%	48.6%	46.7%	45.4%
Preferred stock without mandatory redemption requirements	0.7	0.6	0.7	0.7	0.7
Long-term debt, less current maturities	50.1	48.6	50.7	52.6	53.9
	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 and related notes. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

OVERVIEW

The Holding Company is an investor-owned holding company of energy and energy related companies. Its principal subsidiary, PNM, is an integrated public utility primarily engaged in the generation, transmission, distribution and sale and marketing of electricity; transmission, distribution and sale of natural gas within the State of New Mexico; and the sale and marketing of electricity in the Western United States.

Upon the completion on December 31, 2001, of a one-for-one share exchange between PNM and the Holding Company, the Holding Company became the parent company of PNM. Prior to the share exchange, the Holding Company had existed as a subsidiary of PNM. The new parent 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. The Company is also engaged in the sale and marketing of electricity in the competitive energy market place. As a utility, PNM has an obligation to serve its customers under the jurisdiction of the New Mexico Public Regulation Commission ("PRC"). As a merchant, PNM markets excess production from the utility, as well as unregulated generation, into a competitive marketplace. The Company also has an electric power marketing operation focused on purchasing wholesale electricity in the open market for future resale or to provide energy to jurisdictional customers in New Mexico when the Company's generation assets cannot satisfy demand. The marketing operations utilize an asset-backed marketing strategy, whereby the Company's aggregate net open position for the sale of electricity is covered by the Company's excess generation capabilities.

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 Marketing Operations ("Generation and Marketing"). 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. Unregulated Operations provide energy related services.

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

The Generation and Marketing strategy calls for increased asset-backed marketing and generation capacity supported by long-term contracts, balanced with stringent risk management policies. The Company's future growth plans call for approximately 75% of its new generation portfolio to be committed through long-term contracts, including sales to retail customers. Growth will be dependent on market development, and upon the Company's ability to generate funds for the Company's future expansion. Although the current environment has led the Company to scale back its expansion plans, the Company will continue to operate in the wholesale market. Expansion of the Company's generating portfolio will depend upon acquiring favorably priced assets at strategic locations and securing long-term commitments for the purchase of power from the acquired plants.

RESULTS OF OPERATIONS

YEAR ENDED DECEMBER 31, 2002 COMPARED TO YEAR ENDED DECEMBER 31, 2001

Consolidated

The Company's net earnings available to common shareholders for the year ended December 31, 2002 were $63.7 million, a 57.5% decrease in net earnings from $149.8 million in 2001. This decrease primarily reflects the slowdown in the wholesale electric market, where both prices and market liquidity were significantly lower than the prior year. Despite the slowdown in the wholesale electric market, PNM's electric utility operations recorded an operating income growth of 5.3%. This growth came from a combination of load growth and cost savings, demonstrating the balance the regulated utility provides in the Company's "merchant utility" strategy.

Earnings in 2002 and 2001 were affected by certain non-recurring gains and charges. These special items are detailed in the individual business segment discussions below. The following table enumerates these non-recurring charges and shows their effect on diluted earnings per share, in thousands, except per share amounts.

	2002		[illegible]	
	EARNINGS	**EPS (DILUTED)**	**EARNINGS**	**EPS (DILUTED)**
Net Earnings Available for Common Shareholders	$ 63,686	$1.61	$149,847	$3.77
Adjustment for Special (Gains) and Charges				
(net of income tax effects):				
Realignment costs	5,337	0.14	-	-
Transmission line project write-off	2,911	0.07	-	-
PVNGS* and Four Corners severance costs	942	0.03		
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
Western Resources acquisition and legal costs	(1,471)	(0.04)	10,859	0.27
Total	7,719	0.20	29,627	0.75
Net Earnings Available For Common Shareholders Excluding Special Gains and Charges	$ 71,405	$1.81	$179,474	$4.52

*Palo Verde Nuclear Generating Station ("PVNGS")

To adjust reported net earnings and diluted earnings per share to exclude the non-recurring gains and charges, gains, net of income tax expense, are subtracted from reported net earnings under GAAP, and 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 note in the Notes to Consolidated Financial Statements.

Utility Operations

Electric

The table below sets forth the operating results for the Electric business segment.

	Year Ended December 31,		
	2002	2001	[illegible]
	(In thousands of dollars)		
Operating revenues:			
External customers	$570,089	$559,226	$10,863
Intersegment revenues	707	707	-
Total revenues	570,796	559,933	10,863
Cost of energy sold	3,888	5,102	(1,214)
Intersegment purchases	348,935	341,608	7,327
Total cost of energy	352,823	346,710	6,113
Gross margin	217,973	213,223	4,750
Administrative and other	52,660	48,821	3,839
Depreciation and amortization	34,025	32,666	1,359
Transmission and distribution costs	34,236	37,376	(3,140)
Taxes other than income taxes	12,482	12,336	146
Income taxes	24,121	24,607	(486)
Total non-fuel operating expenses	157,524	155,806	1,718
Operating income	$ 60,449	$ 57,417	$ 3,032

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Operating revenues increased $10.9 million or 1.9% for the period to $570.8 million. Retail electricity delivery grew 2.1% to 7.4 million MWh in 2002 compared to 7.3 million MWh delivered in the prior year, resulting in increased revenues of $14.4 million year-over-year. This volume increase was the result of a weather-driven increase in consumption and continued customer growth. Year-over-year, customer growth was 1.8%. This increase in revenues was partially offset by a decrease of $3.4 million in revenues from third party sales of the Company's transmission capacity due to the slowdown in the wholesale market.

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

Electric Revenues *(In thousands of dollars)*

	Year Ended December 31, 2002	2001
Residential	$ 197,174	$ 187,600
Commercial	247,800	242,372
Industrial	82,009	82,752
Other	43,813	47,209
	$ 570,796	$ 559,933
Average customers	384,478	377,589

The following table shows electric sales by customer class:

Electric Sales *(Megawatt hours)*

	Year Ended December 31, 2002	2001
Residential	2,298,542	2,197,889
Commercial	3,254,576	3,213,208
Industrial	1,612,723	1,603,266
Other	240,665	240,934
	7,406,506	7,255,297

The gross margin, or operating revenues minus cost of energy sold, increased $4.8 million or 2.2%, which reflects the increased energy sales. Electric exclusively purchases power from Generation and Marketing at internally developed prices, which are not based on market rates. These intercompany revenues and expenses are eliminated in the consolidated results.

Total non-fuel operating expenses increased $1.7 million or 1.1%. Administrative and other costs increased $3.8 million or 7.9% due to higher allocated corporate administrative costs of $5.7 million, partially offset by lower bad debt expense of $1.5 million as a result of collection improvements and the absence of losses from the bankruptcy of a significant customer in 2001. Depreciation and amortization increased $1.4 million or 4.2% for the year due to the purchase of transmission plant assets in early 2002. Transmission and distribution costs decreased $3.1 million or 8.4% primarily due to maintenance performed in 2001 to improve system reliability, which did not recur in 2002. Income taxes, which include taxes associated with interest charges, decreased $0.5 million or 2.0% due to lower pre-tax income.

Gas

The table below sets forth the operating results for the Gas business segment.

	Year Ended December 31, 2002	2001	Variance
	(In thousands of dollars)		
Operating revenues	$ 272,118	$ 385,418	$ (113,300)
Total cost of energy	139,045	251,296	(112,251)
Gross margin	133,073	134,122	(1,049)
Administrative and other	53,012	53,093	(81)
Depreciation and amortization	20,964	21,465	(501)
Transmission and distribution costs	29,306	31,072	(1,766)
Taxes other than income taxes	7,793	6,881	912
Income taxes	3,346	3,881	(535)
Total non-fuel operating expenses	114,421	116,392	(1,971)
Operating income	$ 18,652	$ 17,730	$ 922

Operating revenues decreased $113.3 million or 29.4% for the period to $272.1 million, primarily because of lower natural gas prices in 2002 as compared to 2001 and a decrease in gas sales volumes of 6.0%, largely resulting from fewer purchases from Generation and Marketing to support gas-fired generation. Despite the volume decline, customer growth was approximately 2.0%. PNM purchases natural gas in the open market and resells it at cost to its distribution customers. As a result, increases or decreases in gas revenues driven by gas costs do not impact the Company's consolidated gross margin or earnings.

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

Gas revenues *(In thousands of dollars)*

	Year Ended December 31, 2002	2001
Residential	$ 172,200	$ 232,321
Commercial	52,530	68,895
Industrial	2,872	27,519
Transportation*	17,735	20,188
Other	26,781	36,495
	$ 272,118	$ 385,418
Average customers	443,396	434,591

The following table shows gas throughput by customer class:

Gas Throughput *(Thousands of decatherms)*

	Year Ended December 31, 2002	2001
Residential	29,627	27,848
Commercial	12,009	10,421
Industrial	749	3,920
Transportation*	44,889	51,395
Other	4,806	4,355
	92,080	97,939

*Customer-owned gas.

The gross margin, or operating revenues minus cost of energy sold, decreased $1.0 million or 0.8%. This decrease is due mainly to lower consumption of gas for electric generation of $6.0 million partially offset by a 2.0% growth in customer base of $5.0 million. Gross margin is expected to decrease in 2003 due to the expiration of a rate rider in January 2003. The Company currently believes that gas assets are not earning an adequate level of return. As a result, the Company filed a request for increased rates in January 2003. The Company's last gas rate case filing was in October 1997.

Total non-fuel operating expenses decreased $2.0 million or 1.7%. Administrative and other costs decreased only slightly from the prior year. In 2002, the Company recognized lower bad debt expense of $3.0 million because of collection improvements and the absence of losses from the bankruptcy of a significant customer in 2001, lower amortization costs of $1.2 million for SFAS 106 deferred costs (which were fully amortized in 2001), and lower consulting expenses of $0.5 million in connection with cost control and process improvement initiatives in 2001 and lower legal expenses of $0.5 million for routine business matters. These decreases were mostly offset by higher allocated corporate administrative costs of $5.6 million. Transmission and distribution costs decreased $1.8 million or 5.7% primarily due to maintenance performed in 2001 to improve system reliability, which did not recur in 2002. Taxes other than income taxes increased $0.9 million or 13.3% due to the absence of favorable audit outcomes by certain tax authorities recognized in 2001. Income taxes, which include income taxes for interest charges, decreased $0.5 million or 13.8% due to lower pre-tax income

Generation and Marketing Operations

The table below sets forth the operating results for the Generation and Marketing business segment.

	Generation and Marketing Year Ended December 31,		
	(In thousands of dollars)		
Operating revenues:			
External customers	$ 325,385	$ 1,393,635	$ (1,068,250)
Intersegment revenues	348,935	341,608	7,327
Total revenues	674,320	1,735,243	(1,060,923)
Cost of energy sold	406,310	1,267,887	(861,577)
Intersegment purchases	707	707	-
Total cost of energy	407,017	1,268,594	(861,577)
Gross margin	267,303	466,649	(199,346)
Administrative and other	35,452	34,730	722
Energy production costs	146,901	149,585	(2,684)
Depreciation and amortization	43,837	42,766	1,071
Taxes other than income taxes	11,060	8,865	2,195
Income taxes	5,316	80,138	(74,822)
Total non-fuel operating expenses	242,566	316,084	(73,518)
Operating income	$ 24,737	$ 150,565	$ (125,828)

Operating revenues declined $1.1 billion or 61.1% for the year to $674.3 million. This decrease in wholesale electricity sales primarily reflects the slowdown in the wholesale electric market, which resulted from steep declines in wholesale prices and market liquidity as compared to the prior year period.

The significantly higher wholesale pricing in 2001 was driven by increased demand in California, a lack of generating assets to serve the market and the impact of warm weather. By contrast, 2002 has seen relatively mild weather in the West, an abundance of low cost hydropower and weak economic conditions in the region. As a result, the average price realized by the Company fell to approximately $34 per MWh in 2002 versus $111 per MWh in 2001. The low wholesale prices are expected to continue into 2003.

The decline in merchant sales volumes reflect the reduction in market participants in the wholesale market caused by bankruptcy, reduced credit quality of firms in the market and firms exiting the wholesale market. There are also significant unresolved legal, political and regulatory issues that had a dampening effect on activity in the marketplace. As a result, the Company's spot market and short-term sales have declined significantly. The Company delivered wholesale (bulk) power of 9.5 million MWh of electricity for the year ended December 31, 2002, compared to 12.6 million MWh for the same period in 2001.

Although other firms have exited the wholesale market or have had their access to the wholesale market limited due to concerns over credit quality, the Company remains committed to be a participant in this marketplace. While market liquidity is weak, the Company will focus on long-term relationships with smaller wholesale customers (small investor-owned utilities, municipal utilities and co-ops). At the same time, the Company will continue to monitor market conditions. This commitment to the wholesale market leaves the Company poised to participate in the market as liquidity returns and regulatory issues are resolved.

The following table shows revenues by customer class:

Generation and Marketing Revenues

	Year Ended December 31,	
	(In thousands of dollars)	
Intersegment sales	$ 348,935	$ 341,608
Long-term contract	40,132	77,250
Other merchant sales*	266,956	1,313,739
Other	18,297	2,646
	$ 674,320	$1,735,243

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

The following table shows sales by customer class:

Generation and Marketing Sales *(Megawatt hours)*

	Year Ended December 31,	
Intersegment sales	7,406,506	7,255,297
Long-term contract	844,168	1,463,031
Other merchant sales	8,605,987	11,114,069
	16,856,661	19,832,397

The gross margin, or operating revenues minus cost of energy sold, decreased $199.3 million or 42.7%. Lower margins were created primarily by weak pricing, less price volatility and lower market liquidity. In addition, unexpected outages at Four Corners reduced availability of power for wholesale sales. These lower margins were partially offset by a favorable change in the mark-to-market position of the marketing portfolio of $55.3 million year-over-year ($29.5 million gain in 2002 versus $25.8 million loss in 2001). A majority of the gain in 2002 represents the reversal of previously recognized mark-to-market losses.

Total non-fuel operating expenses decreased $73.5 million or 23.3%. Administrative and other costs increased $0.7 million or 2.1% for the year. This increase is primarily due to higher corporate administrative cost allocations of $4.9 million, partially offset by an adjustment of $1.6 million to prior year San Juan Generating Station ("SJGS") participant billings (the Company is the operator of SJGS and shares costs with other owners) and lower costs of $2.3 million resulting from increased capital activity for generation expansion. Energy production costs decreased $2.7 million or 1.8% for the period reflecting the benefits of $2.3 million for the acceleration into 2001 of a planned outage at SJGS, decreased costs of $3.5 million for planned outages at SJGS and an adjustment of $3.6 million to prior year Palo Verde Nuclear Generating Station ("PVNGS") billings from Arizona Public Service Company, the operator of PVNGS. These cost decreases were partially offset by costs of $4.0 million related to the future expansion of Afton Generating Station ("Afton"), severance costs of $1.6 million at PVNGS and Four Corners Power Plant ("Four Corners"), costs of $1.4 million for planned and unplanned outages at Four Corners and costs of $0.8 million at Lordsburg Generating Station ("Lordsburg"), which became fully operational in June 2002. Depreciation and amortization increased $1.1 million or 2.5% due to the addition of Lordsburg. Taxes other than income taxes increased $2.2 million or 24.8% reflecting adjustments recorded in the prior year for favorable audit outcomes by certain tax authorities. Income taxes, which include income taxes for interest charges, decreased $74.8 million or 93.4% due to a decline in pre-tax income.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Corporate

Corporate administrative and general costs, which represent costs that are driven primarily by corporate-level activities, increased $3.0 million or 3.2% for the period to $95.4 million. This increase was due to severance costs of $8.8 million resulting from a realignment of the Company's business structure (the "Realignment"), higher labor of $8.2 million resulting from a transfer of employees from operations to corporate and outside services of $2.9 million primarily related to audit and other consulting services. These increases were partially offset by lower bonus expense of $11.9 million in the current year resulting from lower earnings projections and lower costs of $4.6 million resulting from the reduction of certain unregulated activities. In accordance with EITF 94-3, *Liability Recognition for Certain Employee - Termination Benefits and other Costs to Exit an Activity* ("EITF 94-3"), the Company incurred a liability of $8.8 million for severance and other related costs associated with the involuntary termination of employees in connection with the realignment. As of December 31, 2002, $3.0 million of severance-related benefits were paid and charged against the liability.

Other Non-Operating

Other income decreased by $3.8 million or 7.3% reflecting lower year-over-year returns on investments reflecting market conditions.

Other deductions decreased $54.9 million or 81.7% primarily due to charges in 2001 that did not recur in 2002. In 2001, the Company recognized charges for the write-off of an Avistar investment of $13.1 million, the write-off of non-recoverable coal mine decommissioning costs of $13.0 million, non-recoverable regulatory costs of $11.1 million, a contribution to the PNM Foundation of $5.0 million, and certain costs related to the Company's now terminated acquisition of Western Resources' electric utility operations of $18.0 million. In 2002, the Company recognized a gain from the reversal of a reserve of $2.4 million to reflect the early, successful resolution of the litigation stemming from the terminated Western Resources transaction and a charge of $4.8 million for the cancellation of a transmission line project.

Income Taxes

The Company's consolidated income tax expense was $33.0 million for the year ended December 31, 2002, compared to $81.1 million for the year ended December 31, 2001. The decrease was due to the impact of lower earnings and a decline in the effective tax rate. The Company's effective income tax rates for the years ended December 31, 2002 and 2001 were 33.95% and 35.02%, respectively. The decrease in the effective rate year-over-year was due to the reduction in earnings in 2002 without a corresponding reduction in permanent tax benefits and the recognition of certain affordable housing and research and development credits in 2002.

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 and an active wholesale electric market 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.

	Year Ended December 31,			
	2001		2000	
	Earnings	EPS (Diluted)	Earnings	EPS (Diluted)
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 claims	-	-	(2,808)	(0.07)
Impairment of certain 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 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 note. The tables below set forth the operating results for each business segment.

Utility Operations

Electric

The table below sets forth the operating results for the Electric business segment.

	Year Ended December 31,		
	(In thousands of dollars)		
Operating revenues:			
External customers	$ 559,226	$ 538,758	$ 20,468
Intersegment revenues	707	707	-
Total revenues	559,933	539,465	20,468
Cost of energy sold	5,102	5,048	54
Intersegment purchases	341,608	324,744	16,864
Total cost of energy	346,710	329,792	16,918
Gross margin	213,223	209,673	3,550
Administrative and other	48,821	46,905	1,916
Depreciation and amortization	32,666	31,480	1,186
Transmission and distribution costs	37,376	33,092	4,284
Taxes other than income taxes	12,336	14,102	(1,766)
Income taxes	24,607	27,743	(3,136)
Total non-fuel operating expenses	155,806	153,322	2,484
Operating income	$ 57,417	$ 56,351	$ 1,066

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 from increased activity in the Western power market. 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 *(In thousands of dollars)*

	Year Ended December 31,	
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	377,589	368,506

The following table shows electric sales by customer class:

Electric Sales *(Megawatt hours)*

	Year Ended December 31,	
Residential	2,197,889	2,171,945
Commercial	3,213,208	3,133,996
Industrial	1,603,266	1,544,367
Other	240,934	238,635
	7,255,297	7,088,943

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 Marketing at Company developed prices which are not based on market rates. These intercompany revenues and expenses are eliminated in the consolidated results.

Total non-fuel operating expenses increased $2.5 million or 1.6%. Administrative and general costs increased $1.9 million or 4.1% for the period. This increase is primarily due to higher allocated corporate administrative costs of $5.0 million. 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 of $3.4 million. By December 2000, the Company had resolved most of the problems associated with implementing its new billing system. As a result, bad debt expense was significantly lower in 2001. Depreciation and amortization increased $1.2 million or 3.8% due to a higher depreciable plant base. 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 taxes decreased $1.8 million or 12.5% reflecting favorable audit outcomes by certain tax authorities and tax planning strategies in 2001. Income taxes, which include taxes associated with interest charges, decreased $3.1 million or 11.3% due to lower pre-tax income.

Gas

The table below sets forth the operating results for the Gas business segment.

	Year Ended December 31,		
	[illegible]	[illegible]	[illegible]
	(In thousands of dollars)		
Operating revenues	$ 385,418	$ 319,924	$ 65,494
Total cost of energy	251,296	195,334	55,962
Gross margin	134,122	124,590	9,532
Administrative and other	53,093	44,104	8,989
Depreciation and amortization	21,465	19,994	1,471
Transmission and distribution costs	31,072	27,206	3,866
Taxes other than income taxes	6,881	8,502	(1,621)
Income taxes	3,881	5,680	(1,799)
Total non-fuel operating expenses	116,392	105,486	10,906
Operating income	$ 17,730	$ 19,104	$ (1,374)

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 14.5% or $6.0 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. Approximately $28.1 million of gas revenue in 2001 was attributable to sales to the Company's Generation and Marketing Operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

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

Gas Revenues *(In thousands of dollars)*

	Year Ended December 31, 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	434,591	434,943

The following table shows gas throughput by customer class:

Gas Throughput *(Thousands of decatherms)*

	Year Ended December 31, 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.

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.

Total non-fuel operating expenses increased $10.9 million or 10.3%. Administrative and general costs increased $9.0 million or 20.4%. This increase is due to higher allocated corporate administrative costs of $6.3 million and consulting expenses incurred in connection with cost control and process improvement initiatives, partially offset by decreased bad debt and collection costs of $1.8 million. 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 taxes decreased $1.6 million or 19.1% due to favorable audit outcomes by certain tax authorities. Income taxes, which include taxes for interest charges, decreased $1.8 million or 31.7% due to lower pre-tax income.

GENERATION AND MARKETING OPERATIONS

The table below sets forth the operating results for the Generation and Marketing business segment.

	Year Ended December 31, 2001	2000	Variance
	(In thousands of dollars)		
Operating revenues:			
External customers	$ 1,393,635	$ 750,434	$ 643,201
Intersegment revenues	341,608	324,744	16,864
Total revenues	1,735,243	1,075,178	660,065
Cost of energy sold	1,267,887	749,499	518,388
Intersegment purchases	707	707	-
Total cost of energy	1,268,594	750,206	518,388
Gross margin	466,649	324,972	141,677
Administrative and other	34,730	32,886	1,844
Energy production costs	149,585	137,202	12,383
Depreciation and amortization	42,766	41,559	1,207
Taxes other than income taxes	8,865	11,457	(2,592)
Income taxes	80,138	23,417	56,721
Total non-fuel operating expenses	316,084	246,521	69,563
Operating income	$ 150,565	$ 78,451	$ 72,114

A significant increase in regional wholesale electric prices occurred in the first half of 2001 and the second half of 2000. This increase was caused by, among other things, the power supply/demand imbalance in the Western United States, a lack of generating assets to serve the market and increased natural gas prices. The high wholesale prices seen in 2001 and 2000 did not recur in 2002. At the end of the second quarter of 2001, the market experienced declining 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 participant and limited price volatility.

Operating revenues grew $660.1 million or 61.4% 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 in 2001, compared to 12.4 million MWh in the prior period. The average price realized by the Company increased to approximately $111 per MWh in 2001 compared to $61 per MWh in 2000. Wholesale revenues from third-party customers increased from $750.4 million to $1.4 billion, an 85.7% increase.

The following table shows revenues by customer class:

Generation and Marketing Revenues *(In thousands of dollars)*

	Year Ended December 31, 2001	2000
Intersegment sales	$ 341,608	$ 324,744
Long-term contract	77,250	87,731
Other merchant sales*	1,313,739	655,881
Other	2,646	6,822
	$1,735,243	$1,075,178

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

The following table shows sales by customer class:

Generation and Marketing Sales *(Megawatt hours)*

	Year Ended December 31,	
	[illegible]	[illegible]
Intersegment sales	7,255,297	7,088,943
Long-term contract	1,463,031	330,003
Other merchant sales	11,114,069	12,022,125
	19,832,397	19,441,071

The gross margin, or operating revenues minus cost of energy sold, increased $141.7 million or 43.6%. The Company's margin benefits 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. Margin also benefited from the Company's power marketing 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, marketing volumes rise supporting margin levels in lower price electric markets. These higher margins were partially offset by an unfavorable change in the mark-to-market position of the marketing portfolio of $21.0 million year-over-year ($25.8 million loss in 2001 versus $4.8 million loss in 2000) as the Western power market deterioration in the latter half of 2001 resulted in a reduction of the Company's merchant energy portfolio.

Total non-fuel operating expenses increased $69.6 million or 28.2%. Administrative and general costs increased $1.8 million or 5.6% for the period. This increase is primarily due to higher allocated corporate administrative costs of $5.4 million and higher power marketing expenses of $1.0 million mainly for additional incentive bonuses and consulting fees and other expenses of $0.6 million related to business development and process improvement. This increase was partially offset by lower year-over-year Generation and Marketing business development costs of $4.5 million 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 of $7.9 million in 2001 resulting from scheduled and unscheduled outages at PVNGS, SJGS and Reeves Generating Station ("Reeves"), additional incentive bonuses of $0.5 million at SJGS, and increased operations costs of $1.2 million for 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 of $1.3 million at Four Corners as a result of decreased outage time. A significant unscheduled outage occurred in the fall of 2001 at SJGS, which resulted in higher costs of $2.3 million in 2001. 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 was 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 taxes decreased $2.6 million or 22.6% as a result of favorable audit outcomes by certain tax authorities. Income taxes, which include taxes for interest charges, increased $56.7 million or 242.2% due to an increase in pre-tax income.

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 of 2001. 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 2000 to $4.2 million in 2001 primarily due to decreased costs as a result of the shutdown of certain operations. In January 2002, Avistar was transferred by way of a dividend to Holding Company by PNM.

Corporate

Corporate administrative and general costs, which represent costs that are driven exclusively by corporate-level activities, increased $13.3 million or 16.8% for the period to $92.4 million. This increase was due to increased pension and post-retirement benefits expense of $9.9 million and higher legal costs of $0.8 million associated with routine business operations.

Other Non-Operating Costs

Other income decreased $14.1 million for the year. In 2000, the Company recognized a gain of $13.8 million related to the settlement of a lawsuit.

Other deductions increased $55.3 million for the year. In 2001, the Company recorded charges of $13.1 million to write-off certain permanently impaired Avistar investments, $13.0 million of non-recoverable coal mine decommissioning costs previously established as a regulatory asset, non-recoverable regulatory costs of $11.1 million, a donation of $5.0 million to the PNM Foundation and a charge of $18.0 million related to the Company's terminated acquisition of Western Resources. In 2000, the Company recognized gains of $4.5 million for the reversal of certain reserves associated with the resolution of two gas rate claims and $2.4 million related to the Company's hedge of certain non-qualified retirement plan trust assets. In addition, in 2000, the Company recorded charges of $12.5 million related to the Company's terminated acquisition of Western Resources.

Income Taxes

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. This increase was due to higher earnings in 2001. The Company's effective income tax rates for the years ended 2001 and 2000 were 35.02% and 42.41%, respectively. In 2001, the Company determined that $6.6 million of valuation allowances taken against certain income tax related regulatory assets were no longer required due to changes in the evaluation of its regulatory strategy in light of the holding company filing in May 2001. In 2000, when the allowance was established, management believed these income-tax-related regulatory assets would not be recoverable based on the probable regulatory outcome of industry restructuring in New Mexico. Currently, management fully expects to recover these costs in future rate cases, a situation that was not possible prior to the delay of open access in New Mexico. 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 2001 equity earnings from a passive investment.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

FUTURE EXPECTATIONS

On January 2, 2003, the Company announced that it expects 2003 earnings for the twelve months to be in the range of $1.80 to $2.05. Although the Company's electric utility continues to perform well, the depressed level of wholesale prices in the West, coupled with the significantly decreased marketing activity in that market, has severely limited the earnings potential of Generation and Marketing. This estimated range is based on a number of factors, including growth rates in the New Mexico service territory, wholesale prices, merchant sales velocity (ability to market around assets) and spark spread.

Please note that the following are simplifying guidelines that attempt to quantify a number of complex and interdependent factors affecting the Company's earnings. These are provided to generally assist investors in developing their own independent assessment of the Company's future earnings prospects.

As a result of an agreement ("Global Electric Agreement") approved by regulators in January 2003, retail electric rates will decline by 4% beginning in September 2003, which is projected to reduce earnings by $0.08 per share for the year. The Global Electric Agreement also provides for recovery of $100 million of coal mine decommissioning costs to be amortized over 17 years. Those costs will be amortized beginning September 2003, reducing earnings by $0.03 per share in 2003. Retail electric revenue growth is projected at about 2%, with every 1% increase in load adding $0.05 per share. For further information see "Other Issues Facing the Company – Merchant Plant Filing and Global Electric Agreement."

Return on the Company's gas assets will continue to be poor in 2003. In 2002, this return was below 3%, and in 2003 returns will be reduced by another $3 million through the expiration of an existing rate rider in January 2003. The Company filed a gas rate case in January 2003, seeking a $37.6 million rate increase in cost of service rates and a $1.6 million increase in miscellaneous fees. This case is subject to a ten-month time frame, which may be extended. If an order is received within this time frame, the Company would have some small improvement in earnings per share in December 2003.

On the wholesale side, the baseline forecast assumes continued low liquidity and a marginal improvement in prices. The Company is projecting an average market price of about $34/MWh, around-the-clock on an annualized basis. Although the current forward prices are stronger than this, the forward price curve cannot translate directly to the Company's mix of short-term and long-term sales. A $1 change in market price equals $0.05 per share. The Company is assuming a merchant sales velocity for the year of about 1.5, which is about 50% more power sold than actually generated by PNM. Velocity did pick up at the end of 2002, boosting overall velocity for the year to 1.6. When velocity goes from 1.5 to 1.6, earnings increase $0.01 per share. The Company's 2003 earnings guidance assumes spark spread remains at levels that will restrict operation of PNM's gas fired assets to capacity factors below 10%.

Several increases in cost affect earnings potential in 2003. The Company's earnings assumptions include increased medical and pension costs for the year. The impact of low interest rates and poor market performance on the pension fund in 2002 will be offset somewhat by a $20 million contribution to the fund in 2003. Insurance costs since September 11, 2001 have also risen sharply.

Longer plant maintenance schedules and lost market opportunity from plant unavailability will also put pressure on earnings in 2003. PVNGS will replace a steam generator in Unit 2, which will add forty-two days to its regular planned outage schedule. San Juan has scheduled two major outages this year, extending the regular outage schedule by fifty days more than 2002. In addition, this will be the first full year of operation and maintenance costs and depreciation for the Company's new plants in southern New Mexico, Afton and Lordsburg.

In 2002, the Company's construction expenditures were $240 million of which, $67.0 million was for new generating plants. Over the five-year planning horizon, the Company expects capital expenditures, not inclusive of any generation acquisitions, to average $140 million a year. In 2003, capital expenditures are estimated to be $156 million due to the front loading of certain projects such as the replacement of the steam generator at PVNGS, increased plant outage schedules including a turbine rewind at San Juan, a turbine progress payment and other non-utility capital increases. The Company expects to fund these expenditures from internal cash generation and current debt capacity.

Although other firms have exited the wholesale market or have had their access to the wholesale market limited due to concerns over credit quality, the Company remains committed to be a participant in this marketplace. While market liquidity remains low, the Company will focus on long-term relationships with smaller wholesale customers (small investor-owned utilities, municipal utilities and co-ops). At the same time, the Company will continue to monitor market conditions. This commitment to the wholesale market leaves the Company poised to participate in the market as liquidity returns and regulatory issues are resolved.

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 discussed above.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires that management 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

Unbilled Utility Revenues

Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. The cycle meter reading results in unbilled consumption between the date of the last meter reading in a particular month and the end of the month. This unbilled revenue is estimated each month based on the daily generation volumes, estimated customer usage by class, weather factors, line losses and applicable customer rates based on regression analysis reflecting significant historical trends and experience.

The Company purchases gas on behalf of sales service customers while other marketers or producers purchase gas on behalf of transportation service customers. The Company collects a cost of service revenue for the transportation, delivery, and customer service provided to these customers. Sales-service tariffs are subject to the terms of the Purchase Gas Adjustments Clause ("PGAC") while transportation service customers are metered and billed on the last day of the month. Therefore, the Company estimates unbilled decatherms and cost of service revenues for sales service customers only.

The unbilled decatherms are based on consumption estimates and the associated cost of service revenue for the period. A cycle bill contains an amount for both the current period's consumption and the prior period's consumption. The unbilled portion that is recorded is estimated as a percentage of the next month's budgeted cycle billings. These budgets are prepared using historical data adjusted for known trends, including prior period consumption. Adjustments are also made to the budgeted cycle billings for weather variations above or below normal, customer growth, and any pricing changes by customer rate and revenue class. Any differences between the estimate and the actual cycle billings are recorded in the month billed.

Unbilled Wholesale Power Marketing Revenues

Wholesale power marketing revenues are recognized in the month the energy is delivered to the customer and are based on the actual amounts supplied to the customer. However, in accordance with the Western Systems Power Pool contract, these revenues are billed in the month subsequent to their delivery. Consequently, wholesale power marketing revenues for the last month in any reporting period are unbilled when reported.

Accrued unbilled utility revenues and unbilled wholesale power marketing revenues are combined and specifically identified in the consolidated balance sheets.

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 pursuant to Statement of Financial Accounting Standards, No. 71, *"Accounting for the Effects of Certain Types of Regulation"* ("SFAS 71"). 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 continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, anticipated future regulatory decisions and their impact, competition on the ratemaking process and the ability to recover costs, and the status of any deregulation legislation.

The Company 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 ("Restructuring Act"). The Company evaluated these assets under the same impairment rules that it uses to evaluate tangible long-lived assets. During 2000, the Company entered into negotiations with the PRC staff and other interveners regarding a rate settlement in anticipation of open access occurring in New Mexico under the Restructuring Act. As part of the negotiations, the parties in the settlement discussions agreed on a fixed dollar amount of stranded costs that would be recovered through a non-bypassable wires charge. In 2000, the Company recorded a charge to earnings of $6.6 million as valuation allowances against certain income tax related regulatory assets. This charge was equal to the difference between the agreed to dollar amount and the actual stranded costs that were recorded on the Company's balance sheet. The write-off was not specific to any one particular regulatory asset but was simply the difference between the two previously discussed amounts. Before a final settlement was reached, the New Mexico Legislature in 2001 passed Senate Bill 266, that delayed open access. With the passage of Senate Bill 266, the settlement discussions terminated. Therefore, in 2001 the Company reversed the 2000 valuation allowance as it was determined that it was no longer required due to changes in the evaluation of the Company's regulatory strategy in light of the holding company filing in May 2001.

In August 2001, the Company signed an agreement with San Juan Coal Company ("SJCC") and Tucson Electric Power Company ("Tucson") to replace two surface mining operations with a single underground mine located adjacent to the SJGS. As a result of the negotiations for the new coal contract, the Company recorded a regulatory asset in 1999 for the estimated costs anticipated to close the surface mining operation. This regulatory asset was anticipated to be recovered through the non-bypassable wires charge discussed above. As the settlement discussions progressed, it became clear that a portion of the costs capitalized by the Company for decommissioning the coal mine would not be collectible. As a result, the Company was unable to defer this portion of coal mine decommissioning costs as a regulatory asset for future recovery through regulated rates. Therefore, in 2001, the Company wrote-off $13 million for the portion of coal mine decommissioning costs associated with the Company's FERC firm requirements customers and a portion of SJGS Unit 4. In addition, the Company wrote-off $11.1 million of additional regulatory assets of which $8.1 million related to non-recoverable transition costs and $3 million for other non-recoverable regulatory assets.

On October 10, 2002, the Company and several other parties signed the "Global Electric Agreement", that provides for a five-year rate path for the Company's New Mexico jurisdictional customers beginning in September of 2003. The Global Electric Agreement also seeks to repeal the Restructuring Act. The Company will re-apply SFAS 71 to its Generation and Marketing Operations during the first quarter of 2003 as the Global Electric Agreement was approved by the PRC on January 28, 2003. In connection with the Global Electric Agreement, the Company has agreed to forego recovery of the transition costs incurred to date. The forgone 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 communication costs. The Company will incur a one-time charge of $16.7 million for the non-recoverable transition costs in the first quarter of 2003. As the Company's electric rates are fixed, the opportunity to recover increased costs and the costs of new investment in facilities through rates during the five-year rate freeze period is also limited. The Company will continue to assess the recoverability of its regulatory assets. If future recovery of costs ceases to be probable, the Company would be required to record a charge for the portion of the costs that were not recoverable in current period earnings.

Asset Impairment

The Company evaluates its tangible long-lived assets for impairment whenever indicators of impairment exist pursuant to Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of"* ("SFAS 144"). These potential impairment triggers would include fluctuating market conditions as a result of industry deregulation; planned and scheduled customer purchase commitments; future market penetration; customer growth; fluctuating market prices (resulting from changing fuel costs, other economic conditions, etc.); weather patterns, and other market trends. Accounting rules require that if the sum of the undiscounted expected future cash flows from a company's asset (without interest charges that will be recognized as expenses when incurred), is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset.

Impairment testing for the Company's power generation assets is done in two parts: those power generation assets used to supply New Mexico retail customer needs (evaluated as one group) and those used to supply wholesale market needs (evaluated as another group). Management's assumptions about future prices, volumes, and other market trends in the wholesale electricity market have fluctuated in the past and are expected to continue to be volatile. A significant adverse change in these assumptions may result in an impairment of the Company's power generation assets. Please note that the assumptions inherent in the Company's analysis of asset impairment are inter-dependent. Changes in any one assumption is a simplified view which attempts to give the reader an understanding of the sensitivities affecting the Company's earnings. If market prices were to decrease 22% below the Company's projected average market price of $34/MWh, the Company may be required to recognize a charge to earnings for the related asset impairment in accordance with SFAS 144.

Pension and Other Post-retirement Benefits

The Company and its subsidiaries maintain a qualified defined benefit pension plan (the "Plan"), which covers eligible non-union and union employees including officers. The Plan was frozen at the end of 1997 to new participants, salary levels and benefits. The Company's policy is to fund actuarially-determined contributions.

The Company's income for its Plan approximated $1.4 million for the year ended December 31, 2002, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the Plan assets of 9.0%. In developing the expected long-term rate of return assumption, the Company evaluated input from its actuaries, including their review of asset class return expectations as well as long-term inflation assumptions. This long-term rate of return assumption compares to the historical 10-year compounded return of 8.6% through the end of December 2002. The expected long-term rate of return on the Plan assets is based on an asset allocation assumption of 65% with equity managers, 25% with fixed income managers, and 10% with alternative investments that are primarily real estate and timber. Because of market fluctuation, the Plan's actual asset allocation as of December 31, 2002 was 63% with equity managers, 27% with fixed income managers, and 10% with alternative investments. The Company reviews the actual asset allocation and periodically rebalances the asset allocation to the targeted allocation. The Company continues to believe that 9.0% is a reasonable long-term rate of return on the Plan's assets, despite the recent market downturn in which the Plan assets had an actual loss of 8.3% for the twelve months ended December 31, 2002. The Company will continue to evaluate its actuarial assumptions, including expected rate of return, at least annually, and will adjust as necessary.

The Company bases its determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. If investment return is outside a range of 5% to 13% (expected long-term rate of return plus or minus 4%), this market-related valuation recognizes the portion of return that is outside the range over a five year period from the year in which the return occurs. Since the market-related value of assets recognizes the portion of return that is outside the range over a five-year period, the future value of assets will be impacted as previously deferred returns are recorded.

The discount rate that the Company utilizes for determining future pension obligations is based on a review of long-term high-grade bonds. The discount rate determined on this basis has decreased to 6.75% at September 30, 2002 from 7.50% at September 30, 2001. Based on an expected rate of return on the Plan assets of 9.0%, a discount rate of 6.75% and various other assumptions, it is estimated that the pension expense for the Plan will approximate $3.2 million in fiscal year 2003 and $3.8 million in fiscal year 2004. Future actual pension income or expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in our pension plans.

Lowering the Plan's expected long-term rate of return on pension assets by 0.5% (from 9% to 8.5%) would have lowered pension income for fiscal 2002 by approximately $1.9 million. Lowering the discount rate by 0.5% would have lowered pension income for fiscal year 2002 by approximately $200,000.

The value of the Plan assets has decreased from $339.7 million at September 30, 2001 to $325.1 million at September 30, 2002 including $26.1 million of contributions during 2002. The Company expects to make $20 million in contributions for the 2003 plan year. These contributions are expected to help the Company avoid potential actions of the Pension Benefit Guaranty Corporation for under-funded plans including higher insurance premiums and notification to participants of the under-funded plan status.

Decommissioning Costs

Accounting for decommissioning costs for nuclear and fossil-fuel generation involves significant estimates related to costs to be incurred many years in the future. Changes in these estimates could significantly impact the Company's financial position, results of operation and cash flows. The Company owns and leases nuclear and fossil-fuel facilities that are within and outside of its retail service areas. The Company will adopt the new accounting requirements of Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations"* ("SFAS 143") in the first quarter of 2003. Under SFAS 143, the Company is only required to recognize and measure decommissioning liabilities for tangible long-lived assets for which a legal obligation exists. Adoption of the statement will change the Company's method of accounting for both nuclear generation decommissioning and fossil-fuel generation decommissioning. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - New and Proposed Accounting Standards", for additional discussion regarding the Company's accounting policy for decommissioning and the anticipated effects for adoption of the new standard. Nuclear decommissioning costs are based on site-specific estimates of the costs for removing all radioactive and other structures at the site. PVNGS Unit 3 is currently excluded from the Company's retail rate base while Units 1 and 2 are included in the Company's retail rate base. The Company collects a provision for ultimate decommissioning of Units 1 and 2 in its rates. Fossil-fuel decommissioning costs are also approved by the PRC as a component of the Company's depreciation rates. The Company believes that it will continue to be able to collect for its legal asset retirement obligations for nuclear and fossil-fuel generation activities included in the ratemaking process described above.

In addition, the Company has a contractual obligation with the PVNGS participants to fund separately the nuclear decommissioning at a level in excess of what the Company has identified as its legal asset retirement obligation under SFAS 143. The contractual funding obligation is based on a site-specific estimate prepared by a third party. The Company's most recent site-specific estimates for nuclear decommissioning costs were developed in 2001, using 2001 cost factors, and are based on prompt dismantlement decommissioning, reflecting the costs of removal discussed above, with such removal occurring shortly after operating license expiration. The Company's share of the contractual funding obligation is approximately $201 million (2001 dollars) at December 31, 2002. The estimates are subject to change based on a variety of factors including, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The operating licenses for PVNGS Units 1, 2 and 3 expire in 2024, 2025, and 2027, respectively. The Company does not have a similar contractual funding obligation related to its fossil-fuel plants.

Self-Insurance

The Company self-insures for certain losses related to general liability, workers' compensation and automobile claims. The Company maintains insurance with third-party insurers in excess of the Company's self-insured retentions to limit the Company's exposure per occurrence or accident, as applicable. The Company's self-insurance liabilities reflect the estimated ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are not discounted and are established based upon claims filed, estimated claims incurred but not reported, and analysis of industry and historical data. Management reviews the amounts recorded for these liabilities on a quarterly basis to ensure that they are appropriate. While management believes that these estimates are reasonable based on the information available, the Company's financial results could be impacted if actual trends, including the severity or frequency of claims or fluctuations in premiums, differ from the Company's estimates.

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 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). Subsequent developments could materially alter management's assessment of a matter's probable outcome and the estimate of liability.

Legal Fees

The Company is involved in various legal proceedings in the normal course of business. The associated legal costs for these legal matters are accrued when incurred. It is also the Company's policy to accrue for legal costs expected to be incurred in connection with Statement of Financial Accounting Standards No. 5 *"Accounting for Contingencies"* ("SFAS 5") legal matters when it is probable that a SFAS 5 liability has been incurred and the amount of expected legal costs to be incurred is reasonably estimable. These estimates include costs for external counsel and professional fees.

See "Quantitative and Qualitative Disclosure About Market Risk – Interest Rate Risk and Financial Instruments" for discussion regarding the Company's accounting policies and sensitivity analysis for the Company's financial instruments and derivative energy and other derivative contracts. See also "Planned Financing Activities" below for additional discussion regarding the Company's accounting policies for forward interest swaps.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2002, the Company had cash and short-term cash investments of $83.3 million compared to $179.2 million in cash and short-term and long-term cash investments at December 31, 2001. Certain long-term investments have been reclassified as short-term to reflect the Company's liquidity needs to fund certain construction projects in 2002.

Cash provided from operating activities for the year ended December 31, 2002 was $97.3 million compared to cash provided by operating activities of $327.3 million for the year ended December 31, 2001. This decrease was primarily the result of a decline in operating income due to the deterioration of wholesale market conditions. Also, contributing to the decrease was a payment of $36.0 million for the termination of the surface coal mine contract, the Company's $26.1 million contribution to its pension and post-retirement benefit plans and a payment of $23.2 million to secure a long-term wholesale contract. In addition, the Company did not make its first quarter 2001 estimated federal income tax payment of $32.0 million until January 2002 because of an extension granted by the IRS to taxpayers in several counties in New Mexico as a result of wildfires in 2000. These non-recurring payments reduced operating cash flows below historical levels.

Cash used for investing activities was $200.4 million in 2002 compared to $407.0 million in 2001. Cash used for investing activities includes construction expenditures for new generating plants of $67.4 million in 2002 compared to $70.9 million in 2001. Payments for combustion turbines not yet included in plant were $31.3 million in 2002 compared to $32.6 million in 2001. In addition, cash used for investing in 2001 includes the purchase of short-term and long-term investments of $150.0 million. The change in cash used for investing activities was partially offset by the redemption of short-term investments of $76.6 million in 2002. Expenditures in 2001 reflect the acquisition of certain transmission assets and other related investing activities of $13.9 million.

Cash generated by financing activities was $78.5 million in 2002 compared to $0.4 million in 2001. Financing activities in 2002 were primarily short-term borrowings of $115.0 million compared to $35.0 million in 2001 for liquidity reasons, partially offset by an 8% increase in cash payments for common stock dividends.

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 current construction program is upgrading generation systems, upgrading and expanding the electric and gas transmission and distribution systems, and purchasing nuclear fuel. To preserve a strong financial position, the Company announced in 2002 its plans to eliminate capital expenditures for previously planned generation expansion until market conditions warrant further investment. Projections for total capital requirements for 2003 are $176 million and projections for construction expenditures for 2003 are $156 million including remaining payments on the combustion turbines discussed below. For 2003-2007 projections, total capital requirements are $800 million and construction expenditures are $708 million. These estimates are under continuing review and subject to on-going adjustment.

PNM had previously committed to purchase five combustion turbines for a total cost of $151.3 million. The turbines are for power generation plants with an estimated cost of construction of approximately $370 million over the next five years depending on market conditions. PNM has expended $225 million as of December 31, 2002 of which $144 million was for equipment purchases. On June 27, 2002, Lordsburg, an 80 MW natural gas fired plant, became fully operational and commenced serving the wholesale power market. Afton, a 141 MW simple cycle gas turbine, became fully operational on December 4, 2002. These plants are part of the Company's ongoing competitive strategy of increasing generation capacity over time to serve increasing retail load, sales under long-term contracts and other merchant sales. These plants were not originally planned to serve New Mexico retail customers and therefore are not currently included in the rate base. However, it is possible that these plants may be needed in the future to serve the growing retail load. If so, these plants will have to be certified by the PRC and would then be included in the rate base.

In 2002, the Company utilized cash generated from operations, cash on hand, as well as its liquidity arrangements to cover its construction commitments. The Company anticipates that internal cash generation and current debt capacity will be sufficient to meet all its capital requirements for the years 2003 through 2007. 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 current and future liquidity arrangements.

Liquidity

As of February 28, 2003, PNM had $215 million of liquidity arrangements in addition to $76 million of cash. The liquidity arrangements consist of $195 million from an unsecured revolving credit facility ("Credit Facility") and $20 million in local lines of credit. PNM entered into a new revolving credit facility on December 19, 2002, which increased borrowing capacity from $150 million to $195 million. This facility will mature December 18, 2003. There were $170 million in borrowings against the Credit Facility as of February 28, 2003. In addition, the Holding Company has $15 million in local lines of credit.

The Company's ability, if required, to access the capital markets 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 stable by Moody's Investor Services, Inc. ("Moody's") and Standard and Poor's Ratings Services ("S&P") and positive by Fitch, Inc. ("Fitch"). The Company is committed to maintaining or improving its investment grade ratings. 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 tables show the Company's long-term obligations and commitments as of December 31, 2002.

		Payments Due *(In thousands)*			
Contractual Obligations	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**
Short-Term Debt (a)	$ 150,000	$ 150,000	$ -	$ -	$ -
Long-Term Debt	980,092	1,852	272,728	5,260	700,252
Operating Leases	446,973	28,216	58,216	62,391	298,150
Purchased Power Agreement	213,191	23,889	48,217	34,704	106,381
Coal Contract (b)	1,496,838	106,048	205,229	183,252	1,002,309
Total Contractual Cash Obligations	$3,287,094	$ 310,005	$ 584,390	$ 285,607	$ 2,107,092

(a) Represents the actual outstanding balance of the Credit Facility as of December 31, 2002.
(b) Assumes deliveries under the Coal Contract. If no deliveries are made, certain minimum payments may be required under the Coal Contract.

		Amount of Commitment Expiration Per Period *(In thousands)*			
Other Commercial Commitments	**Total Amounts Committed**	**1 year**	**2-3 years**	**4-5 years**	**After 5 years**
Short-Term Debt (c)	$ 41,500	$ 41,500	$ -	$ -	$ -
Local Lines of Credit	35,000	35,000	$ -	$ -	$ -
Letters of Credit	5,700	5,700	$ -	$ -	$ -
Total Commercial Commitments	$ 82,200	$ 82,200	$ -	$ -	$ -

(c) Represents the unused borrowing capacity of the Credit Facility less outstanding letters of credit of $3.5 million as of December 31, 2002.

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 $13.2 million for the year ended December 31, 2002. The table above reflects the net lease payment.

PNM's other significant operating lease obligations include the EIP, a leased interest in transmission line with annual lease payments of $2.8 million (see "Planned Financing Activities" below), and an operating lease for the entire output of 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 operating lease was $196 million as of December 31, 2002.

PNM has entered into various long-term Purchase Power Agreements ("PPAs") obligating it to buy electricity for aggregate fixed payments of $213.2 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 $85.2 million in fixed payments plus the cost of production and a return. These contracts expire December 2003 through June 2010. PNM's marketing portfolio as of December 31, 2002 included open contract positions to buy $59.7 million of electricity and to sell $56.1 million of electricity. In addition, PNM had open forward positions classified as normal sales of electricity under the derivative accounting rules of $140.7 million and normal purchases of electricity of $98.9 million.

PNM contracts for the purchase of gas to serve its retail 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 PNM recovers 100% of its cost of gas.

Contingent Provisions of Certain Obligations

The Holding 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 Holding Company 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 retail 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 Systems Power Pool ("WSPP") contains a contingent requirement that could require PNM to provide security if its debt were to fall below 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 "ratings trigger." If PNM is downgraded or upgraded by the ratings agencies, the result would be an increase or decrease in interest cost, respectively. 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, inclusive of off-balance sheet debt, of less than 65% as well as maintenance of an earnings before interest, taxes, depreciation and amortization ("EBITDA")/interest coverage ratio of three times. If PNM's debt-to-capital ratio, inclusive of off-balance sheet debt, were to exceed 65% or its interest coverage ratio falls below 3.0, 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, 2002, PNM had $5.7 million of letters of credit outstanding. The outstanding balance of the Credit Facility at December 31, 2002 was $150.0 million.

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

As of December 31, 2002, PNM has $268.4 million of long-term debt that matures in August 2005 excluding sinking fund payments related to EIP secured lease bonds. All other long-term debt of PNM 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 and regulatory agreements would ultimately limit the amount of additional debt PNM would issue.

PNM currently has $46 million of tax-exempt bonds outstanding that were callable at a premium beginning December 15, 2002, and an additional $136 million that become callable at a premium in August 2003. PNM intends to refinance these bonds, assuming the interest rate of the refinancing does not exceed the current interest rate of the bonds, and has hedged the entire planned refinancing. The Company received regulatory approval to refund the tax-exempt bonds on October 29, 2002. This approval is effective for one year. In order to take advantage of current low interest rates, PNM entered into five forward starting interest rate swaps in the fourth quarter of 2001 and the first quarter of 2002. 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 rate on the refinancing to 4.95% plus an adjustment for PNM's and the industry's credit rating. PNM's assessment of hedge effectiveness is based on changes in the hedge 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. For the year ended December 31, 2002, PNM recognized $0.4 million of hedge ineffectiveness in earnings. At December 31, 2002, the fair market value of these derivative financial instruments was approximately $18.4 million unfavorable to the Company.

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 benchmark. The five forward starting interest rate swaps have a termination date of May 15, 2003 for a combined notional amount of $182.0 million. There were no fees on the transaction, as they are imbedded in the rates, and the transaction will be settled in cash 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 provided that the forecasted transactions (interest payments) occur as anticipated. The Company would seek regulatory approval to recover any hedge cost which could not be capitalized under the accounting rules in its next litigated electric rate proceeding.

On November 1, 2002, the Company filed for approval from the PRC to enter into a transaction providing for the securitization of PNM's retail electric service accounts receivable, wholesale electric service accounts receivables and retail gas services accounts receivable ("Securitization") to reduce the amount of debt outstanding under the Credit Facility and to raise cash for PNM's ongoing working capital requirements and other capital requirements. The total capacity, or maximum that could be borrowed, under the Securitization will not exceed $100 million. In the proposed transaction, PNM would sell its accounts receivables from time to time. The PRC approved this request on December 17, 2002. The Company expects to enter into this transaction in March 2003.

PNM has notified the Holding Company that it intends to exercise its early buyout option related to its 60% ownership interest in the EIP transmission line and related facilities. In conjunction with the early buyout option, PNM will retire the related $26.2 million of 10.25% debt. PNM caused the related notification of mandatory redemptions to be distributed on February 24, 2003, calling the debt on April 1, 2003. Additionally, the Company acquired the remaining $12.5 million of publicly-traded EIP Secured Facility Bonds. These bonds have been retired and ownership of the related lease debt is expected to be transferred to PNM, subject to regulatory approvals.

Dividends

The Holding Company's Board of Directors regularly reviews the dividend policy. The declaration of common dividends is dependent upon a number of factors including the ability of the Holding Company's subsidiaries to pay dividends. Currently, PNM is the Holding 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 the Holding Company. PNM cannot pay dividends that will cause its debt rating to go below investment grade; and PNM cannot pay dividends in any year, as determined on a rolling four-quarter basis, in excess of net earnings for that year without prior PRC approval. In January 2003, with the signing of the Global Electric Agreement, the PRC modified the PNM dividend restriction to allow PNM to dividend future equity contributions made by the Holding Company back to the Holding Company. Additionally, PNM has various financial covenants, which limit the transfer of assets, whether through dividends or other means.

In addition, the ability of the Holding Company to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of earnings, its financial circumstances and performance, the effect of regulatory decisions and legislative activities, future growth plans, the related capital requirements, standard business considerations and market and economic conditions generally.

Consistent with the PRC's holding company order, PNM paid dividends of $127.0 million to the Holding Company on December 31, 2001. On March 4, 2002, the PNM Board of Directors declared a dividend of $5.5 million, which was paid on March 19, 2002. On June 10, 2002, the PNM Board of Directors declared a dividend of $24.7 million, which was paid on June 28, 2002.

On February 18, 2003, the Holding Company's Board of Directors approved a 4.5% increase in the common stock dividend. The increase raised the quarterly dividend to $0.23 per share, for an indicated annual dividend of $0.92 per share.

Capital Structure

The Company's capitalization, including current maturities of long-term debt, at December 31, 2002 and 2001 are shown below:

	2002	2001
Common Equity	49.2%	50.8%
Preferred Stock	0.7	0.6
Long-term Debt	50.1	48.6
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 operating lease, which was $196 million as of December 31, 2002 and $224 million as of December 31, 2001.

OTHER ISSUES FACING THE COMPANY - RESTRUCTURING THE ELECTRIC UTILITY INDUSTRY

State

In April 1999, the New Mexico Electric Utility Industry Restructuring Act of 1999 ("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 delayed 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. 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.

On October 10, 2002, PNM announced that it had agreed with the PRC Staff, the New Mexico Attorney General, and other consumer groups on the Global Electric Agreement that includes agreement to support repeal of a majority of the Restructuring Act, as amended. The Global Electric Agreement, which includes agreement on a five-year rate path, procedures for the Company's participation in merchant plant activities and other regulatory issues, was approved by the PRC on January 28, 2003. The New Mexico Legislature is currently in session. Legislation repealing the Restructuring Act, as amended, and continuing the authorization for utilities to participate in merchant plant activities for a limited time has been introduced as SB 718. On February 28, 2003, SB 718 passed the Senate by a vote of 37-2. It is now awaiting action in the House of Representatives. The Company is unable to predict at this time if restructuring will occur as provided in current law or, if so, what form it will take. (See "Merchant Plant Filing and Global Electric Agreement" below).

The Restructuring Act, as amended, recognized 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 would 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. Approximately $135 million of costs associated with the power supply and energy services businesses under the Restructuring Act, as amended, 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. See Note 12 of the notes to consolidated financial statements for further develpments.

Federal

The 107th Congress adjourned without passing comprehensive energy legislation. Both the House and the Senate passed energy legislation but were unable to resolve disagreement on a number of provisions during conference committee discussions. President Bush has expressed his continuing commitment to his National Energy Policy and has urged Congress to move forward with energy legislation. Key committee chairs in both the House and the Senate have expressed desires to move quickly on a comprehensive energy bill. The Company is unable to predict if energy legislation will be passed or if passed, what form it will take, or if it will be signed by the President if passed.

MERCHANT PLANT FILING AND GLOBAL ELECTRIC AGREEMENT

Senate Bill ("SB 266"), enacted by the 2001 session of the New Mexico legislature, allowed public utilities to "invest in, construct, acquire or operate" generating plants not intended to provide retail electric service ("merchant plant"), 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 PRC can ensure the utility will meet its duty to provide service when the utility invests in merchant plant, how that plant will be financed and how transactions between regulated services and merchant plants will be conducted. The PRC initiated proceedings to address these issues.

In November 2001, PNM began negotiations with the PRC utility staff and intervenors in order to resolve its merchant plant filing and other matters. Discussions included the future framework for restructuring the electric industry in New Mexico under the Restructuring Act, a future retail electric rate path and PNM's merchant plant filing.

The year-long negotiations ended on October 10, 2002 with the filing of the Global Electric Agreement with the PRC. The Global Electric Agreement sets a rate path through 2007 and resolves the issues surrounding industry deregulation in New Mexico and PNM's merchant power strategy. The Global Electric Agreement was signed by PNM, the PRC Staff, the New Mexico Attorney General's Office, the New Mexico Industrial Energy Consumers, the City of Albuquerque, and the University of New Mexico. The United States Executive Agencies ("USEA") subsequently agreed to support the Global Electric Agreement as if they had signed it. The Global Electric Agreement also provides for the signatories to support passage of legislation to repeal the Restructuring Act and concerning merchant plant activities in the New Mexico Legislature. The Global Electric Agreement was approved by the PRC on January 28, 2003.

Under the Global Electric Agreement, PNM will decrease retail electric rates 6.5% in two phases over the next three years. The first phase will be a 4.0% decrease, effective September 2003. The second phase will be a further 2.5% decrease from current rate levels, effective in September 2005. Rates would then be frozen at that level until the end of 2007. The Company expects to achieve necessary cost savings through additional cost efficiencies and fuel savings. The risks and benefits of all wholesale electric sales, inure solely to the Company's shareholders until December 2007. Since the Global Electric Agreement does not provide for a fuel cost adjustment, the lower fuel costs sought to be captured by shifting to underground mining for the coal supplies at SJGS will flow through to the Company's earnings largely offsetting the reduction in retail revenues.

PNM will be able to seek a general rate adjustment during the rate freeze period if complying with any new or changed environmental or tax law or regulation, or a new broader application of existing environmental or tax laws or regulations, would compromise its financial integrity. PNM also is permitted to capitalize the reasonable costs of mandatory renewable energy resources, including an after-tax cost of capital of 8.64% to be recorded concurrently with the deferral of those costs.

PNM is authorized to recover in the stipulated rates and future retail rates, its New Mexico jurisdictional share of the decommissioning costs associated with the San Juan, La Plata and Navajo surface coal mines. PNM is allowed to recover up to $100 million of the costs, composed of approximately $69 million in surface coal mine reclamation costs, and approximately $31 million of contract buyout costs, without being subject to prudence challenge by the signatories to the Global Electric Agreement. The costs will be amortized over 17 years commencing September 1, 2003 and in equal amounts each year thereafter. PNM cannot seek to recover a return on the unamortized reclamation costs, but could seek to recover a return on the unamortized contract buyout costs remaining as of December 31, 2007 in future rate adjustment proceedings.

The stipulated rates also provide for full recovery of nuclear decommissioning costs accrued in accordance with the estimates in the applicable decommissioning cost study during the rate freeze period for PNM's interests in PVNGS Units 1 and 2. The portion of SJGS Unit 4 previously treated as an excluded resource from PNM's New Mexico retail rates are included as a generation resource to serve PNM's New Mexico retail and wholesale firm requirements customers' load. PNM's contracts to purchase power from Tri-State, Delta and firm power from Southwestern Public Service Comapny ("SPS") would also be included as generation resources to serve PNM's New Mexico retail and wholesale firm requirements customers' load until each contract expires under the Global Electric Agreement.

PRC approval or other authorization from the PRC is not required for PNM's merchant plant investment as long as PNM meets the following conditions: (a) PNM does not invest more than $1.25 billion in merchant plant; (b) PNM has an investment grade credit rating on a stand-alone basis and on a consolidated basis with the Holding Company; and (c) PNM spends at least $60 million per year in gas and electric utility, non-merchant plant infrastructure needed to maintain adequate and reliable service. No prior approval for merchant plant participation would be required and expedited PRC approval would be available for financing of merchant plant if certain specified financial conditions are met. If PNM's credit rating on a stand-alone or consolidated basis with the Holding Company falls below investment grade, however, approvals are needed for new merchant plant projects and for continuing to participate in merchant plant projects of more than certain dollar value and under certain conditions.

PRC approval is not required for PNM to transfer any part of its interests in merchant plant or PVNGS Unit 3 from time to time to any other legal entity, provided that the following conditions are met: (a) PNM's debt to capital ratio will not exceed 65% after giving effect to the transfer and (b) PNM's investment grade status on a stand-alone basis and on a consolidated basis with the Holding Company will not be impaired by the transfer of merchant plant or PVNGS Unit 3 at the time of transfer.

PNM further agreed in the Global Electric Agreement that it will transfer all its interests in merchant plant out of PNM by January 1, 2010. PNM will accelerate the mandatory transfer to a date one year after PNM has completed expenditures of $1.25 billion on merchant plant. PNM may seek a variance from the PRC at any time prior to January 1, 2010 to extend or vacate the time or terms and conditions requiring the transfer but not beyond January 1, 2015.

Under the Global Electric Agreement, if merchant plant or PVNGS Unit 3 is transferred to a PNM affiliate, PNM's generation resources and the affiliate's generation resources may be jointly dispatched at the merchant affiliate's sole discretion until January 1, 2015. Joint dispatch of all utility, PVNGS Unit 3 or merchant plant resources would be terminable at any time between 2008 and 2015 at PNM's discretion, as long as the utility's dispatch capability is not impaired in any way.

PNM agreed to forego recovery of the costs incurred in preparing to transition to a competitive retail market in New Mexico. This will result in a one-time charge of approximately $16.7 million, pre-tax, in the first quarter of 2003.

In the Global Electric Agreement, PNM, PRC utility staff and intervenors agreed to actively support the repeal of a majority of the Restructuring Act, as amended. Legislation repealing the Restructuring Act, as amended, and continuing authorization for utilities to participate in merchant plant for a limited time has been introduced as SB 718. On February 28, 2003, SB 718 passed the Senate by a vote of 37-2. It is now awaiting action in the House of Representatives. If the repeal does not occur during the 2003 New Mexico Legislative Session, various modifications to the conditions of the Global Electric Agreement are triggered depending on how long repeal is delayed.

In summary, the terms of this Global Electric Agreement and the Company's continuing efforts to control expenses offer significant benefits to both customers and shareholders in the form of lower rates, a predictable rate path, and the resolution of important issues affecting implementation of the Company's strategic plan over the next several years.

The Company is currently unable to predict the impact these proceedings may have on its plans to expand its generating capacity and its future financial condition and results of operations.

WATER SUPPLY

There is a growing concern in New Mexico about the use of water for power plants, due to the state's arid climate and current drought conditions. The availability of sufficient water supplies to meet all the needs of the state, including growth, is a major issue. An interim committee of the legislature refused to support legislation mandating the use of dry cooling technology. However, legislation requiring a water conservation plan as part of an application for siting generation plants of a certain size is being considered in the 2003 session. In building the Afton and Lordsburg plants, the Company has secured sufficient water rights.

The Four Corners region, in which SJGS and Four Corners are located, has been experiencing drought conditions that may affect the water supply for the plants in 2003, as well as later years if adequate moisture is not received in the watershed that supplies the area. United States Bureau of Reclamation ("USBR") is working to assess the adequacy of the water supply under PNM's USBR contract for 16,200 acre feet of water that supplies SJGS. Additionally, various stakeholders in the San Juan Basin, including the New Mexico State Engineer, are evaluating what water rights might be affected by the drought conditions, including water rights pursuant to the New Mexico state permit that provide 8,000 acre feet of water to SJGS and approximately 28,000 acre feet of water for Four Corners. PNM is assessing alternatives for temporary supplies of water and is working with USBR and area stakeholders to minimize the effect on operations of the plants. PNM has assessed its situation with regard to the drought and the alternatives available to it and does not believe that its operations will be materially affected at this time. However, PNM cannot forecast the weather situation and its ramifications with any degree of certainty or how regulators and legislators may impact PNM's situation in the future, should the drought continue.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

WESTERN UNITED STATES WHOLESALE POWER MARKET

A significant portion of the Company's earnings in 2001 was derived from the Company's wholesale power marketing operations, which benefited from strong demand and high wholesale prices in the Western United States. These market conditions were driven by a number of separate factors, including electric power supply shortages in the Western United States during the first half of 2001, weather conditions, gas supply costs and transmission constraints. As a result of these factors, 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.

These conditions resulted in the well-publicized "California energy crisis" and in the bankruptcy filings of the California Power Exchange ("Cal PX") and of Pacific Gas and Electric Company ("PG&E"), although the turmoil in the Western markets was not limited to California. However, since the third quarter of 2001, conditions in the Western wholesale power market have changed substantially as the result of certain regulatory actions (see below), moderate weather conditions, conservation measures, the construction of additional generation, and a decline in natural gas prices, as well as the lingering slowdown in the regional economy. These changes have placed and are expected to continue to place downward pressure on wholesale electricity prices.

In response to the turmoil in the Western energy market, the FERC initially imposed a "soft" price cap of $150 per MWh for sales to the 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 modified by orders of the FERC 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. Shortly thereafter, 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. This plan replaced the $150 per MWh soft cap previously established and applied during periods of system emergency. Subsequently, the FERC issued still another order that changed the previous orders and expanded the price mitigation approach to the entire Western region.

In July 2002, the FERC issued further orders to address wholesale power prices in the Western market. On July 11, the FERC established a price cap of $91.87 per MWh for the period ending September 30, 2002. On July 17, the FERC entered an order, which was to have taken effect October 1, 2002, raising the price cap to $250 per MWh. However, the FERC extended the $91.87 per MWh price cap through October 31, 2002. According to the FERC, this price cap will spur new investment in generation and will foster the eventual return of a robust competitive marketplace. The July 17 order also established mechanisms to prevent power suppliers from engaging in market manipulation activities.

As a result of the foregoing conditions in the Western market, the FERC and other federal and state governmental authorities are conducting investigations and other proceedings relevant to the Company and other sellers. The more significant of these in relation to the Company are summarized below.

California Refund Proceeding

By order dated June 19, 2001, in response to a complaint filed by San Diego Gas and Electric Company ("SDG&E") and other California buyers against sellers into the California wholesale electric market, the FERC directed one of its administrative law judges ("ALJ") to convene a settlement conference to address potential refunds owed by sellers into the California market. The settlement conference, in which PNM participated, was ultimately unsuccessful, and the ALJ recommended to the FERC that an evidentiary hearing be held to resolve the dispute, suggesting that refunds were due; however, the estimated refunds were significantly lower than those demanded by California, and in most instances, were offset by the amounts due suppliers from the Cal PX and Cal ISO. The California parties had demanded refunds of approximately $9 billion from power suppliers. Hearings on the refunds were held in September 2002 and the ALJ issued his Proposed Findings on California Refund Liability on December 12, 2002, in which he determined that the Cal ISO had, for the most part, calculated the amounts of the refunds correctly. In his appendix identifying the amounts of the refunds, he identified what he termed "ballpark" figures for the amount of refunds due under his order. PNM was identified as having a refund liability of approximately $4.3 million, while being owed approximately $7 million from the Cal ISO. Pursuant to the FERC's order, PNM filed, in conjunction with the competitive supplier group, initial comments on January 13, 2003 to the ALJ's preliminary findings addressing errors the Company believes the ALJ made in his proposed findings and reply comments on February 3, 2003. Prior to the December 12, 2002 ALJ decision, the Ninth Circuit Court of Appeals ordered FERC to allow the parties in the case to provide additional evidence in the case. Several California parties submitted additional evidence on March 3, 2003, which they argue supports their position that virtually all market participants either engaged in specific market manipulation strategies or facilitated such strategies, including PNM. PNM maintains that it did not engage in improper wholesale trading activities. PNM, along with other members of the competitive supplier group, will file reply evidence on March 20, 2003. PNM cannot predict what effect this additional evidence will have on the prior decision of the ALJ as to specific refund amounts. The Company is unable to predict the ultimate outcome of this FERC proceeding, or whether PNM will be directed to make any refunds as the result of a FERC order.

Pacific Northwest Refund Proceeding

In addition to the California refund proceedings, Puget Sound Energy, Inc., filed a complaint at FERC alleging that spot market prices in the Pacific Northwest wholesale electric market were unjust and unreasonable. On September 24, 2001, the ALJ issued a recommended decision and declined to order refunds associated with wholesale electric sales in the Pacific Northwest. Prior to the FERC acting on the ALJ's recommended decision, several parties joined in filing a motion at the FERC requesting the FERC to reopen the proceeding, in view of the issuance of the FERC Staff's report on the Enron trading strategies, to permit further investigation and discovery into transactions in the wholesale electric market in the Pacific Northwest. The FERC re-opened the docket to receive additional evidence from the parties. The FERC did not remand the case to the ALJ, but determined to undertake themselves the review of any additional evidence in conjunction with the ALJ's recommended decision. On March 3, 2003, Puget Sound and other parties submitted additional evidence to FERC alleging the existence of unlawful wholesale electric prices in the Pacific Northwest and that FERC should require sellers to provide refunds for spot market bilateral sales transactions in the Pacific Northwest. The Company believes there is nothing in this additional evidence that requires FERC to reverse the prior decision of the ALJ denying refunds. The Company is unable to predict the ultimate outcome of this FERC proceeding, or whether PNM will be directed to make any refunds as the result of an order by the FERC.

FERC Investigation of "Enron-Like" Trading Practices

The FERC has also initiated a market manipulation investigation, partially in response to the bankruptcy filing of the Enron Corporation ("Enron") and to allegations that Enron may have engaged in manipulation of portions of the Western wholesale power market. In connection with that investigation, all FERC jurisdictional and non-jurisdictional sellers into Western electric and gas markets have been required to submit data regarding short-term transactions in 2000-2001. PNM made its data submission on April 2, 2002. Subsequently, in May 2002, new Enron documents came to light that raised additional concerns about Enron's trading practices. In light of these new revelations, the FERC issued additional orders in the pending investigation requiring sellers to respond to detailed questions by admitting or denying that they had engaged in trading practices similar to those practiced by Enron and certain other sellers, including so-called "wash" transactions. The FERC issued supplemental requests for data submissions. In its responses to the FERC requests, PNM denied that it had engaged in improper activities such as those identified in Enron's memos and also denied engaging in "wash" transactions. PNM admitted engaging in certain activities described in the memos that were not improper. Where appropriate, PNM's responses addressed any arguable similarities between any of its trading activities and those under investigation by the FERC. The FERC staff has issued a preliminary report on its findings, recommending that the FERC initiate formal investigative proceedings directed at three companies and the FERC has done so. The Company was not among the companies named. The Company cannot predict the outcome of this investigation.

California Power Exchange and Pacific Gas and Electric ("PG&E") Bankruptcies

In January and February 2001, Southern California Edison Company and PG&E, major purchasers of power from the Cal PX and Cal 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. PG&E subsequently also sought bankruptcy protection. PNM has filed its proofs of claims in the Cal PX and PG&E bankruptcy proceedings. Total amounts due PNM 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.

California Attorney General Complaint

In March 2002, the California Attorney General filed a complaint with the FERC against numerous sellers regarding prices for wholesale electric sales into the Cal ISO and Cal PX and to the California Department of Water Resources ("Cal DWR"). PNM was among the sellers identified in this complaint and filed its answer and motion to intervene. In its answer, PNM defended its pricing and challenged the theory of liability underlying the California Attorney General's complaint. On May 31, 2002, the FERC entered an order denying the California Attorney General's request to initiate a refund proceeding, but directed sellers, including PNM, to comply with additional reporting requirements with regard to certain wholesale power transactions. PNM has made filings required by the May 31, 2002 order. The California Attorney General filed a request for rehearing contesting the FERC decision. On September 23, 2002, the FERC issued its order denying the California Attorney General's request for rehearing. The California Attorney General has filed a petition for review in the United States Court of Appeals for the Ninth Circuit. PNM has intervened in the Ninth Circuit appeal and intends to participate as a party in that proceeding. The Company cannot predict the outcome of this appeal. As addressed below, the California Attorney General has also threatened litigation against PNM in state court in California based on similar allegations.

California Attorney General Threatened Litigation

The California Attorney General has filed several lawsuits in California state court against certain power marketers for alleged unfair trade practices involving alleged overcharges for electricity. By letter dated April 9, 2002, the California Attorney General notified

PNM of its intention to file a complaint in California state court against PNM concerning its alleged failure to file rates for wholesale electricity sold in California and for allegedly charging unjust and unreasonable rates in the California markets. The letter invited PNM to contact the California Attorney General's office before the complaint was filed, and PNM has met several times with representatives of the California Attorney General's office. Further discussions are contemplated. To date, a lawsuit has not been filed by the California Attorney General and the Company cannot predict the outcome of this matter.

California Antitrust Litigation

Several class action lawsuits have been filed in California state courts against electric generators and marketers, alleging that the defendants violated the law by manipulating the market to grossly inflate electricity prices. Named defendants in these lawsuits include Duke Energy Corporation ("Duke") and related entities along with other named sellers into the California market and numerous other "unidentified defendants." These lawsuits were consolidated for hearing in state court in San Diego. In May 2002, the Duke defendants in the foregoing state court litigation served a cross-claim on PNM. Duke also cross-claimed against many of the other sellers into California. Duke asked for declaratory relief and for indemnification for any damages that might ultimately be imposed on Duke. Several defendants removed the case to federal court. The federal judge has entered an order remanding the matter to state court, but the filing of various procedural motions has delayed the effect of this ruling. PNM has joined with other cross-defendants in motions to dismiss the cross-claim. The Company believes it has meritorious defenses but cannot predict the outcome of this matter.

Block Forward Agreement Litigation

On February 1, 2002, PNM was served with a declaratory relief complaint filed by the State of California in California state court. The state's declaratory relief complaint seeks a determination that the state is not liable for its commandeering of certain energy contracts known as "Block Forward Agreements". The Block Forward Agreements were a form of futures contracts for the purchase of electricity at below-market prices and served as security for payment by PG&E and SCE for their electricity purchases through the Cal PX. When PG&E and SCE defaulted on payment obligations incurred through the Cal PX, the Cal PX moved to liquidate the Block Forward Agreements to satisfy in part the obligations owed by PG&E and SCE. Before the Cal PX could liquidate the Block Forward Agreements, California commandeered them for its own purposes. In March 2001, PNM and other similarly situated sellers of electricity through the Cal PX filed claims for damages with the California state Victims Compensation and Government Claims Board ("Victims Claims Board") on the theory that the state, by commandeering the Block Forward Agreements, had deprived them of security to which they were entitled under the terms of the Cal PX's tariff. The Victims Claims Board filing was an administrative remedy that served as a mandatory prerequisite to filing suit against the state for recovery of damages related to the commandeering of the Block Forward Agreements. The Victims Claims Board denied PNM 's claim on March 22, 2002. PNM filed a complaint against the State of California in California state court on September 20, 2002 seeking damages for the state's commandeering of the Block Forward Agreements and requesting judicial coordination with the state's declaratory relief action filed in February 2002 on the basis that the two actions raise essentially the same issues. The California State court stayed the proceedings through April 11, 2003 pending resolution of certain related issues before the FERC.

EFFECTS OF CERTAIN EVENTS ON FUTURE REVENUES

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

On April 29, 2002, the FERC issued its Final Order directing PNM to provide the service. The Company filed an appeal of the April 29th order in the United States Court of Appeals for the 10th Circuit. The Company, USEA and WAPA entered a binding memorandum of understanding resolving the dispute. The memorandum provided that upon approval by the PRC of the Agreement resolving the Company's electric rate path and merchant plant issues described earlier in Merchant Plant Filing and Global Electric Agreement, the Company would dismiss its appeal at the Tenth Circuit and WAPA would purchase from the Company approximately 60 MW of electric power that will be wheeled under the FERC Final Order to serve KAFB. The power sales agreement between the Company and WAPA was executed on February 3, 2003. On March 1, 2003 the power sales agreement went into effect and the Company dismissed its appeal at the 10th Circuit on March 5, 2003.

Due to the price difference between New Mexico jurisdictional retail sales rates and the wholesale rates under the power sales agreement between the Company and WAPA, the loss in revenue is expected to be $2.8 million per year beginning in 2004.

In a separate but related proceeding, PNM and the United States Executive Agencies on behalf of KAFB are involved in a PRC case regarding a dispute over specific Company tariff language under which PNM provides service to KAFB. The PRC case was held in abeyance, pending the outcome of the FERC proceeding. A status conference is scheduled before the PRC Hearing Examiner to determine how to proceed with the case due to the dismissal of the Tenth Circuit appeal and implementation of the power sales agreement between WAPA and the Company.

NEW SOURCE REVIEW RULES

In November 1999, the Department of Justice at the request of the Environmental Protection Agency ("EPA") filed complaints against seven companies alleging the companies over the past 25 years had made modifications to their plants in violation of the New Source Review ("NSR") requirements and in some cases the New Source Performance Standard ("NSPS") regulations, which could result in the requirement to make costly environmental additions to older power plants. 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, several of the pending cases are approaching trial, and a trial has commenced in one of the cases. No complaint has been filed against PNM by the EPA, 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 Environmental Department ("NMED") made an information request of PNM, advising PNM 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." PNM has responded to the NMED information request. In late June 2002, PNM received another information request from the NMED for a list of capital projects budgeted or completed in 2001 or 2002. PNM has responded to this additional NMED information request.

The National Energy Policy released in May 2001 by the National Energy Policy Development Group called for a review of the pending EPA enforcement actions. As a result of that review, on June 14, 2002, the EPA announced its intention to pursue steps to increase energy efficiency, encourage emissions reductions and make improvements and reforms to the NSR program. The EPA announced that, among other things, the NSR program had impeded or resulted in the cancellation of projects that would maintain or improve reliability, efficiency and safety of existing power plants. The EPA's June 2002 announcement contemplated further rulemakings on NSR-related issues and expressly cautioned that the announcement was not intended to affect pending NSR enforcement actions. Thereafter, on December 31, 2002, the EPA promulgated certain long-awaited revisions to the NSR rules, along with proposals to revise the routine maintenance, repair and replacement exclusion contained in the regulations. There is no specific timetable for these revisions and the ultimate resolution of NSR-related issues raised by the enforcement actions remains unclear. If the EPA were to prevail in the position advanced in the pending litigation, 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.

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 PNM of GCT's intent to file a so-called "citizen suit" under the Clean Air Act, alleging that PNM and co-owners of the SJGS violated the Clean Air Act, and the implemention of federal and state regulations, at SJGS. Pursuant to that notification, on May 16, 2002, the GCT filed suit in federal district court in New Mexico against PNM (but not against the other SJGS co-owners). The suit alleges two violations of the Clean Air Act and related regulations and permits. First, 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 SJGS Units 3 and 4. Second, 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 lawsuit seeks penalties as well as injunctive and declaratory relief. PNM filed its answer in federal court on June 6, 2002, denying the material allegations in the complaint. Both sides in the litigation have filed motions for partial summary judgment, but the court has, to date, made no rulings on any of these matters. A trial date on liability issues has been scheduled on a trailing docket for June 2003. Based on its investigation to date, the Company firmly believes that the allegations are without merit and PNM vigorously disputes the allegations. PNM has always adhered and continues to adhere to high environmental standards as evidenced by its ISO 14000 certification. 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 PNM line near the location. The explosion destroyed a small building and injured two persons who were working in the building. PNM's investigation indicates that the leak was an isolated incident likely caused by a combination of corrosion and increased pressure. PNM also cooperated with an investigation of the incident by the PRC's Pipeline Safety Bureau (the "Bureau"), which issued its report on March 18, 2002. The Bureau's report gave PNM notice of probable violations of the New Mexico Pipeline Safety Act and related regulations. PNM and the Bureau staff entered a compliance agreement addressing the probable violations and filed it with the PRC for approval on March 4, 2003. PNM agreed to undertake a list of twenty-four corrective actions, including internal policy changes, retraining employees and enhancing gas line monitoring. PNM has also agreed to voluntarily accelerate spending on pipeline replacement by more than $10.0 million and to commit an additional $1.8 million to development and implementation of systems to improve gas line management. The compliance agreement is pending before the PRC. Two lawsuits against PNM by the injured persons along with several claims for property and business interruption damages have been resolved.

LANDOWNER ENVIRONMENTAL CLAIMS

In March 2002, a lawsuit was filed in New Mexico state court by a landowner owning property in the vicinity of SJGS, against PNM and SJCC. The lawsuit was served on the defendants on June 11, 2002. The complaint seeks $20 million in damages, plus pre-judgment interest and punitive damages, based on allegations related to the alleged discharge of pollutants into an arroyo near the plant, including damage to the plaintiff's livestock. A jury trial has been demanded. PNM has denied the allegations of wrong-doing and is vigorously defending this matter, but is unable to predict the outcome of this matter.

ARCHEOLOGICAL SITE DISTURBANCE

The Company hired a contractor, Great Southwestern Construction, Inc. ("Great Southwestern"), to conduct certain "climb and tighten" activities on a number of electric transmission lines in New Mexico between July 2001 and December 2001. Those lines traverse a mix of federal, state, tribal and private properties in New Mexico. In late May 2002, the U.S. Forest Service ("USFS") notified PNM that apparent disturbances to archeological sites had been discovered in and around the rights-of-way for PNM's transmission lines in the Carson National Forest in New Mexico. Great Southwestern performed "climb and tighten" activities on those transmission lines. PNM has confirmed the existence of the disturbances, as well as disturbances associated with certain arroyos that may raise issues under section 404 of the Clean Water Act. PNM has given the Corps of Engineers notice concerning the disturbances in arroyos. The Corps of Engineers has acknowledged the Company's notice and asked PNM to cooperate in addressing these disturbances. No formal or written demand by the USFS has been made on the Company with respect to this matter, but the USFS has verbally instructed PNM to undertake an assessment and possible related mitigation measures with respect to the archeological sites in question. PNM contracted for an archeological assessment and a proposed remediation plan with respect to the disturbances and has provided the assessment to the USFS and the federal Bureau of Land Management ("BLM"). PNM has provided Great Southwestern with notice and a demand for indemnity. A subsequent preliminary investigation into other transmission lines that were covered by the "climb and tighten" project indicated that there are disturbances on lands governed by other federal agencies and Indian tribes. PNM and Great Southwestern have provided notice of the potential disturbances to these other agencies and tribes. No formal action has been initiated against PNM and no notice of any contemplated action has been received. The Company had been informed that the USFS and BLM had commenced a criminal investigation into Great Southwestern's activities on this project. However, the Company recently received verbal confirmation that the USFS and the BLM have decided to decline criminal prosecution. The State of New Mexico recently requested information from PNM concerning the location of potential disturbances on state lands. The Navajo Nation has also requested further information concerning disturbances on Navajo land. The Company is unable to predict the outcome of this matter and cannot estimate with any certainty the potential impact on the Company's operations.

DUGAN PRODUCTION CORPORATION LITIGATION

On July 30, 2002, Dugan Production Corp. filed a lawsuit in the County of San Juan, New Mexico, against the SJCC. On September 2, 2002, the SJCC removed the lawsuit to the United States District Court for the District of New Mexico. The lawsuit seeks to enjoin the underground mining of coal from a portion of the land that is to be used for the underground mine. The plaintiff also seeks monetary damages.

The SJCC, through leases with the federal government and the State of New Mexico, owns coal interests with respect to the underground mine. The plaintiff, through leases with the federal government, the State of New Mexico and certain private parties, claims to own certain oil and gas interests in portions of the land that is to be used for the underground mine. The plaintiff alleges that the SJCC's underground coal mining operations have or will interfere with plaintiff's gas production and result in the dissipation of natural gas that it otherwise would be entitled to recover. The plaintiff also alleges, and seeks a declaration by the court, that the rights under its leases are senior and superior to the rights of the SJCC.

The SJCC has informed the Company that SJCC intends to vigorously dispute the litigation. On September 17, 2002, the SJCC filed a motion to dismiss the claims against it on several grounds. Discovery for the lawsuit has not yet started. The Company cannot predict the ultimate outcome of the litigation or whether the litigation will adversely affect the amount of coal available, or its price for SJGS.

EXCESS EMISSIONS REPORTS

As required by law, whenever there are excess emissions from SJGS, due to such causes as start-up, shutdown, upset, breakdown or certain other conditions, PNM makes filings with the NMED. For some two years, PNM has been in discussions with NMED concerning excess emissions reports for the period after January 1997. NMED is still in the process of investigating the circumstances of these excess emissions and whether these emissions involve any violation of applicable permits and regulations. PNM and NMED have entered into several agreements tolling the running of the statute of limitations in order to allow NMED to complete its review of these filings. The present tolling agreement expires March 14, 2003. PNM has been advised by NMED counsel that NMED is in the process of preparing a draft administrative compliance order addressing certain claimed violations, but PNM has not seen this draft order and has not had a chance to meet with NMED to address any violations that might be claimed. The Company is unable to predict the outcome of this matter and cannot estimate the potential impact on the Company's operations.

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. SFAS 143 requires the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development and or the normal operations of the long-lived assets. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the standard, the asset retirement obligation ("ARO") liability is recognized at its fair value as incurred.

The recognition of an ARO results in an increase in the carrying cost of the long-lived asset, which will be amortized using a systematic and rationale basis over the remaining life of the related asset as depreciation expense. An ARO represents a future liability and, as a result, accretion expense will be accrued on this liability until such time as the obligation is satisfied. Accretion of the ARO liability due to the passage of time is recorded as an operating expense. If at the end of the asset's life the recorded liability differs from the actual settled obligation, the Company may incur a gain or loss that will be recognized at that time. The net difference between the amounts determined under SFAS 143 and the Company's previous method of accounting for such activities net of expected regulatory recovery, will be recognized as a cumulative effect of a change in accounting principle, net of related income taxes. The Company is currently calculating the liability associated with its AROs but does not believe there will be a material effect on continuing operations for the adoption of this standard.

Statement of Financial Accounting Standards No. 145, *"Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections"* ("SFAS 145"). In April 2002, the FASB issued SFAS 145. This statement updates and clarifies existing accounting pronouncements for the treatment of gains and losses from extinguishment of debt and eliminates an inconsistency between required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have similar economic effects as sale-leaseback transactions. In accordance with previous accounting standards, gains and losses from extinguishment of debt were classified as extraordinary gains and losses. The current statement permits gains and losses from extinguishment of debt to be classified as ordinary and included in income from operations, unless they are unusual in nature or occur infrequently and therefore included as an extraordinary item.

SFAS 145 is effective for fiscal years beginning after May 15, 2002 for the provisions related to the rescission of FASB Statements No. 4, 44 and 64, and for all transactions entered into after May 15, 2002 for the provision related to the amendments of FASB Statement No. 13. The Company does not believe there will be a material effect from the adoption of this standard on the Company's consolidated statements of financial position or results of operations.

Statement of Financial Accounting Standards No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"* ("SFAS 146"). In July 2002, the FASB issued SFAS 146. This statement requires that a liability for a cost associated with an exit or disposal activity be recognized at fair value when the liability is incurred and is effective for exit or disposal activities that are initiated after December 31, 2002 and nullifies EITF 94-3, *"Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)."* It also substantially nullifies EITF Issue No. 88-10, *"Costs Associated with Lease Modification or Termination."* Previously issued financial statements, including interim financial statements, cannot be restated. The Company does not expect its adoption of this standard in fiscal year 2003 to have a significant impact on its financial statements.

Statement of Financial Accounting Standards No. 148, *"Accounting for Stock-Based Compensation – Transition and Disclosure, Amendment of FASB Statement No. 123 and APB Opinion No. 28"* ("SFAS 148"). In December 2002, the FASB issued SFAS 148 that amended SFAS 123 to provide alternative methods of transition to SFAS 123's fair value method of accounting for stock-based employee compensation but does not require fair value accounting as prescribed in SFAS 123. SFAS 148 is effective for fiscal years ending after December 15, 2002. It also amends the disclosure provisions of SFAS 123 and Accounting Principles Board Opinion No. 28 to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. The disclosure provisions of SFAS 148 are incremental to the existing disclosure requirements of SFAS 123 and are applicable to all companies with stock-based compensation. The Company adopted the disclosure requirements of this standard in fiscal year 2002, but continues to account for stock-based compensation under APB 25.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Financial Accounting Standards Board ("FASB") Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, an interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34"* ("FIN 45"). In November 2002, the FASB issued FIN 45 which enhances the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. FIN 45 applies to contracts or indemnification agreements that contingently require the guarantor to make payments to the guaranteed party based on changes in an underlying obligation that is related to an asset, liability, or an equity security of the guaranteed party. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The initial recognition and initial measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of initial application should not be revised or restated. The Company adopted FIN 45, and such adoption did not have material impact on the financial statements.

Financial Accounting Standards Board ("FASB") Interpretation No. 46, *"Consolidation of Variable Interest Entities"*, an interpretation of Accounting Research Bulletin (ARB) No. 51, *"Consolidated Financial Statements"* ("FIN 46"). In January 2003, the FASB issued FIN 46 to address the consolidation of variable interest entities that have one or both of the following characteristics: (1) the equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, which is provided through other interests that will absorb some or all of the expected losses of the entity and (2) the equity investors lack one or more of the following essential characteristics of a controlling financial interest: (a) the direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights, (b) the obligation to absorb the expected losses of the entity if they occur, which makes it possible for the entity to finance its activities, or (c) the right to receive the expected residual returns of the entity if they occur, which is the compensation for the risk of absorbing the expected losses. FASB believes that if a business enterprise has a controlling financial interest in a variable interest entity, the assets, liabilities, and results of the activities of the variable interest entity should be included in consolidated financial statements with those of the business enterprise. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. There are also additional disclosure requirements for an enterprise that holds significant variable interests in a variable interest entity but is not the primary beneficiary. FIN 46 applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date and may be applied prospectively with a cumulative effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. Currently, the Company does not have interests in any variable interest entity.

EITF 02-3 *"Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities"*, EITF 98-10 *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities"*, and Statement of Financial Accounting Standards No. 133 ("SFAS 133"), *"Accounting for Derivative Instruments and Hedging Activities"*. On October 25, 2002, the EITF reached a final consensus on EITF 02-3 that rescinds EITF 98-10 and requires that all energy contracts held for trading purposes be presented on a net margin basis in the statement of earnings. The rescission of EITF 98-10 requires that energy contracts which do not meet the definition of a derivative under SFAS 133 no longer be marked-to-market and recognized in current earnings. As a result, all contracts which were marked-to-market under EITF 98-10 and must now be accounted for under the accrual method should be written back to cost with any difference included as a cumulative effect adjustment in the period of adoption. This transition provision will be effective for the first quarter of 2003. The rescission of EITF 98-10 did not have a material impact on the Company's financial condition or results of operations as all contracts previously marked-to-market under the definition provided in EITF 98-10 also met the definition of a derivative under SFAS 133 and are properly recorded at fair value with gains and losses recorded in earnings. The Company is reviewing its energy contract portfolio to determine whether its contracts meet the definition of trading activities under EITF 02-3 which should be presented on a net margin basis. The Company will reclassify prior periods to a net margin basis for those contracts previously accounted for under EITF 98-10 in the first quarter of 2003. The Company does not expect to report revenues and cost of energy sold on a net margin basis on a prospective basis as a result of the application of EITF 02-3 as none of the of Company's marketing activities meet the definitions of trading activities as prescribed by EITF 02-3.

DISCLOSURE REGARDING FORWARD LOOKING STATEMENTS

Statements made in this filing 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. Future financial results will be affected by a number of factors, including interest rates, weather, fuel costs, changes in supply and demand in the market for electric power, wholesale power prices, market liquidity, the competitive environment in the electric and natural gas industries, the performance of generating units and transmission system, state and federal regulatory and legislative decisions and actions, and the performance of state, regional and national economies.

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 wholesale power marketing transactions in order to take advantage of favorable price movements and market timing activities in the wholesale power markets. 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 Holding Company Board of Directors. The Board's Finance Committee sets the risk limit parameters. The Risk Management Committee ("RMC"), comprised of corporate and business segment officers and other managers, 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 segments; recommendation of the types of instruments permitted; authority to establish a general policy regarding counterparty exposure and limits; authorization and delegation of transaction limits; review and approval of controls and procedures; 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; review of hedging 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 procedures and policies 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 unit's policies address the following controls: authorized risk exposure limits; authorized instruments and markets; authorized personnel; policies on segregation of duties; policies on mark-to-market accounting; responsibilities for deal capture; confirmation procedures; responsibilities for reporting results; statement on the role of derivative transactions; and limits on individual transaction size (nominal value).

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

Marketing and procurement of energy often involves 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 counterparties and adequacy of the control environment. PNM 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 Marketing Operations.

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

Under the derivative accounting rules and the related accounting rules for energy contracts, 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 contracts which meet the definition of a derivative under SFAS 133 and do not qualify for a normal purchase or sale designation are recorded on the balance sheet at fair market value at each period end. The changes in fair market value are recognized in earnings unless specific hedge accounting criteria are met. Should an energy transaction qualify as a hedge, fair market value changes from year to year 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 following table shows how the net fair value of mark-to-market energy contracts was derived from the amounts included in the balance sheet:

	Year Ended December 31,	
	[illegible]	[illegible]
	(In thousands of dollars)	
Mark-to-Market Energy Contracts:		
Current asset	$ 4,531	$ 9,461
Long-term asset	267	1,469
Total mark-to-market assets	4,798	10,930
Current liability	(5,725)	(36,256)
Long-term liability	-	(5,114)
Total mark-to-market liabilities	(5,725)	(41,370)
Net fair value of mark-to-market energy contracts	$ (927)	$ (30,440)

The mark-to-market energy portfolio positions at December 31, 2002 and December 31, 2001 represent net liabilities after netting all open purchase and sale contracts. Because the contractual amounts required to settle the open net liability were greater than the current market values of the contracts, the Company recorded a net loss position in 2002 and 2001; however, the settlement of certain of these transactions in 2002 and changes in market prices significantly reduced the loss position and resulted in the recognition of a mark-to-market gain.

The market prices used to value PNM's mark-to-market energy portfolio are based on closing exchange prices and over-the-counter quotations. As of December 31, 2002 and December 31, 2001, PNM did not have any outstanding contracts that were valued using methods other than quoted prices. The Company did not change its methods for valuing its mark-to-market energy portfolio in 2002 as compared to 2001.

The following table provides detail of changes in the Company's mark-to-market energy portfolio net asset or liability balance sheet position from one period to the next:

	Year Ended December 31,	
	[illegible]	[illegible]
	(In thousands of dollars)	
Sources of Fair Value Gain/(Loss)		
Fair value at beginning of year	$ (30,440)	$ (4,643)
Amount realized on contracts delivered during period	26,339	2,239
Changes in fair value	3,174	(28,036)
Net fair value at end of period	$ (927)	$ (30,440)
Net change recorded as mark-to-market	$ 29,513	$ (25,797)

This table provides the maturity of the net assets/liabilities of the Company, giving an indication of when these mark-to-market amounts will settle and generate/(use) cash:

	Fair Value at December 31, 2002		
Sources of Fair Value	**1 year**	**Less than 1-3 Years**	**Total**
	(In thousands of dollars)		
Mark-to-market energy contracts	$ (1,194)	$ 267	$ (927)

Note: All values determined using broker quotes.

As of December 31, 2002, a decrease in market pricing of PNM's mark-to-market energy portfolio by 10% would have resulted in a decrease in net earnings of less than 1%. Conversely, an increase in market pricing of this portfolio by 10% would have resulted in an increase in net earnings of less than 1%.

At December 31, 2002, the market value of PNM's normal sales and purchases of electricity was a $54.6 million asset using the valuation methods described above. If these transactions did not meet the definition of normal under the accounting rules for derivatives, the Company would have recognized unrealized gains of $56.3 million as an adjustment to Generation and Marketing operating revenues based on the change in fair value of these contracts from January 1, 2002 to December 31, 2002.

The Company assesses the risk of these long-term contracts and merchant sales activities using the VAR method 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's VAR calculation only considers the Company's forward position for the proceeding eighteen months. 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 PNM'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'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 PNM's wholesale power marketing portfolios 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 PNM's wholesale power marketing portfolios during the year.

The Company accounts for the sale of electric generation in excess of its retail needs or the purchase of power for retail needs as normal purchases and sales under SFAS 133. Purchases for resale and subsequent resales are accounted for as energy trading contracts in accordance with EITF 98-10 and comprise PNM's mark-to-market portfolio. The VAR for the mark-to-market portfolio was $72,027 at December 31, 2002. The Company also calculates a portfolio VAR, which in addition to its mark-to-market portfolio includes all contracts designated as normal sales and purchases, hedges, and its estimated excess generation assets. This excess is determined using average peak forecasts for the respective block of power in the forward market. The Company's portfolio VAR was $2.0 million at December 31, 2002.

The following table shows the high, average and low market risk as measured by VAR on the Company's mark-to-market portfolio (three day holding period, 99% two-tailed confidence level):

Year Ended December 31, 2002

High		
	(In thousands of dollars)	
$3,408	$1,112	$29

Credit Risk

PNM is exposed to credit losses in the event of non-performance or non-payment by counterparties. The Company uses a credit management process to assess 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. PNM's credit risk with its largest counterparty as of December 31, 2002 was $18.7 million.

In 2001, in response to the increased credit risk and market price volatility described above, the Company provided an allowance against revenue of $12.0 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. As of December 31, 2001, $8.9 million was transferred to the allowance for bad debt. The Company reduced its reserves by $0.6 million for the year ended December 31, 2002 as a result of a

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

lack of market liquidity, lower prices and lower volatility. Based on information available at December 31, 2002, the Company believes the total allowance for anticipated losses (exclusive of bad debt), currently established at $2.4 million, is adequate for management's estimate of losses from credit risk. The Company will continue to monitor the wholesale power marketplace and adjust its estimates accordingly.

The following table provides information related to PNM's credit exposure, net of collateral as of December 31, 2002. It further delineates that exposure by the credit worthiness (credit rating) of the counterparties and provides guidance as to the concentration of credit risk to individual counterparties PNM may have.

Schedule of Wholesale Power Marketing Credit Risk Exposure December 31, 2002

Rating (a)	Exposure Before Credit Collateral(b)	Credit Collateral(c)	Net Exposure	Number of Counter-parties >10%	Net Exposure of Counterparties >10%
			(Dollars are in thousands)		
Investment grade	$35,397	$ -	$35,397	1	$18,732
Non-investment grade	4,837	-	4,837		-
Split rating	20	-	20		-
Internal ratings					
Investment grade	635	-	635		-
Non-investment grade	15,446	211	15,235	1	6,096
Total	$56,335	$ 211	$56,124		$24,828
Credit reserves			$ 2,433		

(a) Rating - Included in "Investment Grade" are counterparties with a minimum Standard & Poor's rating of BBB- or Moody's rating of Baa3. If the counterparty has provided a guarantee by a higher rated entity (e.g., its parent), determination is based on the rating of its guarantor. The "Internal Ratings - Investment Grade" includes those counterparties that are internally rated as investment grade in accordance with the guidelines established in the Company's credit policy.

(b) The Exposure Before Credit Collateral is the net credit exposure to PNM from its wholesale power marketing activities. This includes long-term contracts and other merchant sales and purchases. The exposure captures the net amounts due to PNM from receivables/payables for realized transactions, delivered and unbilled revenues, and mark-to-market gains/losses (pursuant to contract terms). Exposures are offset according to legally enforceable netting arrangements. Amounts are presented before those reserves that are determined on a portfolio basis. (See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Western United States Wholesale Power Market" for discussion of the reserves.)

(c) The Credit Collateral reflects the face amount of cash deposits, letters of credit and performance bonds received from counterparties.

PNM hedges certain portions of natural gas supply contracts in order to protect its retail 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 purchased gas adjustment clause. As a result, earnings are not affected by gains and losses generated by these instruments.

Interest Rate Risk

As of December 31, 2002, the Company has an investment portfolio of fixed-rate government obligations and corporate securities, which were 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, 2002, the fair value of these instruments would decline by 0.7% or $0.6 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 and obligors and limits credit exposure to high investment grade quality investments.

PNM 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 4.05% or $38.8 million if interest rates were to decline by 50 basis points from their levels at December 31, 2002. As of December 31, 2002, the fair value of PNM's long-term debt was $960 million as compared to a book-value of $954 million. In general, an increase in fair value would impact earnings and cash flows if PNM were to re-acquire all or a portion of its debt instruments in the open market prior to their maturity. Certain issuances of the debt have call dates in December 2002 and August 2003. To hedge against the risk of rising interest rates and their impact on the economics of calling the debt, PNM has entered into forward starting interest rate swaps in 2001 and 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 4.95% plus an adjustment for PNM's and the industry's credit ratings. At December 31, 2002, the fair market value of these derivative financial instruments was approximately $18.4 million unfavorable to the Company.

PNM contributed $6.1 million in 2001 to a trust established to fund decommissioning costs for PVNGS. In January 2002, PNM contributed $23.5 million for plan year 2001 to the trust for the Company's pension plan, and other post retirement benefits. Additional contributions were made in September 2002 for $1.1 million and in December 2002 for $1.5 million for the 2002 plan year. The securities held by the trusts had an estimated fair value of $63.2 million as of December 31, 2002, of which approximately 27% 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, 2002, the decrease in the fair value of the securities would be 3.2% or $4.3 million. PNM does not currently recover or return through rates any 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. (For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Pension and Other Post-Retirement Benefits").

Equity Market Risk

As discussed above under Interest Rate Risk, PNM contributes to trusts established to fund its share of the decommissioning costs of PVNGS and pension and other post-retirement benefits. The trusts hold certain equity securities as of December 31, 2002. These equity securities also expose the Company to losses in fair value. Approximately 65% of the securities held by the various trusts were equity securities as of December 31, 2002. Similar to the debt securities held for funding decommissioning and certain pension and other post-retirement costs, PNM does not recover or earn a return on through rates, any losses or gains on these equity securities. (For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Pension and Other Post-Retirement Benefits.")

In 2001, the Company implemented an enhanced cash management strategy using derivative instruments based on the Standard & Poor's 100, S&P 500, and Nasdaq composite 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 has VAR and stop-loss limits established. Trades are typically closed-out before the end of a reporting period and within the same day of execution. There were no open positions as of December 31, 2002.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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 and Ethics Committee of the Board of Directors of PNM Resources, Inc., 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 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 AUDITORS

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

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of PNM Resources, Inc. and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of earnings, retained earnings, comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2002. 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 of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of PNM Resources, Inc. and subsidiaries as of December 31, 2002 and 2001, and results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

DELOITTE & TOUCHE LLP

Omaha, Nebraska
February 11, 2003

CONSOLIDATED STATEMENTS OF EARNINGS

	Year Ended December 31,		
	[illegible]	[illegible]	[illegible]
	(In thousands, except per share amounts)		
Operating Revenues: (notes 1 and 2)			
Electric	$ 895,474	$ 1,952,861	$ 1,289,192
Gas	272,118	385,418	319,924
Unregulated businesses	1,404	1,538	2,158
Total operating revenues	1,168,996	2,339,817	1,611,274
Operating Expenses:			
Cost of energy sold	550,053	1,524,285	949,880
Administrative and general	146,231	155,392	147,268
Energy production costs	149,528	152,455	139,894
Depreciation and amortization	102,409	96,936	93,059
Transmission and distribution costs	63,870	69,001	60,330
Taxes, other than income taxes	34,244	30,302	34,405
Income taxes (note 1 and 8)	20,887	88,769	53,964
Total operating expenses	1,067,222	2,117,140	1,478,800
Operating income	101,774	222,677	132,474
Other Income and Deductions:			
Other income	48,360	52,147	66,246
Other deductions	(12,306)	(67,257)	(11,950)
Income tax (expense) benefit (notes 1 and 8)	(12,144)	7,706	(20,382)
Net other income and deductions	23,910	(7,404)	33,914
Earnings before interest charges	125,684	215,273	166,388
Interest Charges:			
Interest on long-term debt (note 4)	56,409	62,716	62,823
Other interest charges	5,003	2,124	2,619
Net interest charges	61,412	64,840	65,442
Net Earnings	64,272	150,433	100,946
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 63,686	$ 149,847	$ 100,360
Net Earnings per Share of Common Stock (Basic) (note 7)	$ 1.63	$ 3.83	$ 2.54
Net Earnings per Share of Common Stock (Diluted) (note 7)	$ 1.61	$ 3.77	$ 2.53
Dividends Paid per Share of Common Stock	$ 0.86	$ 0.80	$ 0.80

The accompanying notes are an integral part of these financial statements

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
CONSOLIDATED BALANCE SHEETS

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31, 2002	2001	2000
		(In thousands)	
Balance at Beginning of Year	$ 415,388	$ 296,843	$ 227,828
Net earnings before preferred stock dividends	64,272	150,433	100,946
Dividends (note 4):			
Cumulative preferred stock	(586)	(586)	(586)
Common stock	(34,423)	(31,302)	(31,345)
Balance at End of Year	$ 444,651	$ 415,388	$ 296,843

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

CONSOLIDATED BALANCE SHEETS

ASSETS

	As of December 31, 2002	2001
	(In thousands)	
Utility Plant (notes 1, 11 and 12)		
Electric plant in service	$2,301,673	$2,117,947
Gas plant in service	615,907	575,350
Common plant in service and plant held for future use	79,987	45,223
	2,997,567	2,738,520
Less accumulated depreciation and amortization	1,330,376	1,251,801
	1,667,191	1,486,719
Construction work in progress	173,248	246,278
Nuclear fuel, net of accumulated amortization of $16,568 and $16,954	26,832	26,940
Net utility plant	1,867,271	1,759,937
Other Property and Investments:		
Other investments (notes 1, 6 and 12)	442,704	552,453
Non-utility property, net of accumulated depreciation of $1,750 and $1,580	1,528	1,784
Total other property and investments	444,232	554,237
Current Assets:		
Cash and cash equivalents	3,702	28,408
Accounts receivables, net of allowance for uncollectible accounts of $15,575 and $18,025	76,850	84,620
Unbilled revenues (note 1)	49,079	62,377
Other receivables	47,122	51,883
Inventories (note 1)	37,230	36,483
Regulatory assets (note 3)	24,027	10,473
Short-term investments (note 1)	79,630	45,111
Other current assets	32,753	33,243
Total current assets	350,393	352,598
Deferred charges:		
Regulatory assets (note 3)	196,283	195,367
Prepaid retirement cost (note 9)	39,665	18,273
Other deferred charges	129,063	33,376
Total deferred charges	365,011	247,016
	$3,026,907	$2,913,788

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

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	As of December 31, 2002	2001
	(In thousands)	
Capitalization:		
Common stockholders' equity:		
Common stock outstanding - 39,118 shares, no par value (note 4)	$ 624,119	$ 625,632
Accumulated other comprehensive loss, net of tax	(94,721)	(28,996)
Retained earnings	444,651	415,388
Total common stockholders' equity	974,049	1,012,024
Minority interest (notes 1 and 5)	11,760	11,652
Cumulative preferred stock without mandatory redemption requirements (note 4)	12,800	12,800
Long-term debt (note 4)	980,092	953,884
Total capitalization	1,978,701	1,990,360
Current Liabilities:		
Short-term debt	150,000	35,000
Accounts payable	97,968	76,141
Accrued interest and taxes (notes 1 and 8)	46,189	72,022
Other current liabilities	99,019	149,454
Total current liabilities	393,176	332,617
Deferred Credits:		
Accumulated deferred income taxes (notes 1 and 8)	125,595	120,153
Accumulated deferred investment tax credits (notes 1 and 8)	41,583	44,714
Regulatory liabilities (note 3)	52,019	54,295
Regulatory liabilities related to accumulated deferred income tax (note 3)	14,137	14,163
Accrued post-retirement benefit cost (note 9)	17,335	14,929
Other deferred credits (note 13)	404,361	342,557
Total deferred credits	655,030	590,811
Commitments and Contingencies (note 12)	-	-
	$ 3,026,907	$2,913,788

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, (In thousands)		
Cash Flows From Operating Activities:			
Net earnings	$ 64, 272	$ 150,433	$ 100,946
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	115,415	106,768	103,829
Accumulated deferred investment tax credit	(3,131)	(3,139)	(3,143)
Accumulated deferred income tax	47,269	(32,927)	21,215
Asset write-offs	4,817	24,079	-
Write-off Avistar investments	-	12,417	-
Non-recurring merger costs	(2,436)	17,975	6,700
Net unrealized losses on trading and investment contracts	(29,513)	26,172	370
Wholesale credit reserve	-	(5,406)	8,456
Other, net	2,083	(4,297)	(330)
Changes in certain assets and liabilities:			
Accounts receivables	10,220	92,990	(90,680)
Other assets	(52,655)	32,481	(32,444)
Accounts payable	23,660	(137,073)	107,346
Other liabilities	(82,750)	46,873	17,250
Net cash flows provided by operating activities	97,251	327,346	239,515
Cash Flows From Investing Activities:			
Utility plant additions	(240,225)	(264,844)	(146,878)
Redemption of short-term investments	76,633	-	-
Return of principal PVNGS lessor notes	17,531	16,674	16,668
Merger acquisition costs	-	(11,567)	(6,700)
Short-term and long-term investments	-	(150,000)	-
Other	(54,366)	2,723	(20,590)
Net cash flows used for investing activities	(200,427)	(407,014)	(157,500)
Cash Flows From Financing Activities:			
Borrowings (note 4)	115,000	35,000	-
Repayments (note 4)	-	-	(32,800)
Exercise of employee stock options (note 10)	(2,412)	(2,179)	(1,232)
Common stock repurchase (note 4)	-	-	(27,867)
Dividends paid	(34,226)	(31,876)	(32,265)
Other	108	(560)	(559)
Net cash flows provided by (used for) financing activities	78,470	385	(94,723)
Decrease in Cash and Cash Equivalents	(24,706)	(79,283)	(12,708)
Beginning of Year	28,408	107,691	120,399
End of Year	$ 3,702	$ 28,408	$ 107,691
Supplemental cash flow disclosures:			
Interest paid, net of capitalized interest	$ 53,041	$ 62,216	$ 64,045
Income taxes paid, net	$ 13,541	$ 72,146	$ 50,480
Long-term debt assumed for transmission line	$ 26,152	$ -	$ -

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

	As of December 31,	
	(In thousands)	
Common Stock Equity:		
Common Stock, no par value (note 4)	$ 624,119	$ 625,632
Accumulated other comprehensive income, net of tax	(94,721)	(28,996)
Retained earnings	444,651	415,388
Total common stock equity	974,049	1,012,024
Minority Interest (notes 1 and 5)	11,760	11,652
Cumulative Preferred Stock: (note 4)		
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, 2002 were 128,000	12,800	12,800
Long-Term Debt: (note 4)		
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
EIP debt due 2003-2012	26,152	-
Other, including unamortized discounts	(350)	(406)
Total long-term debt	980,092	953,884
Total Capitalization	$ 1,978,701	$ 1,990,360

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2002	2001	2000
		(In thousands)	
Net Earnings Before Preferred Stock Dividends	$ 64,272	$150,433	$100,946
Other Comprehensive Income (Loss), net of tax:			
Unrealized gain (loss) on securities:			
Unrealized holding gains arising during the period	1,303	70	2,508
Reclassification adjustment for losses included in net income	(919)	(526)	(4,887)
Minimum pension liability adjustment	(55,061)	(28,858)	
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	(10,361)	345	-
Reclassification adjustment for losses included in net income	(687)	(6,148)	
Total Other Comprehensive Loss	(65,725)	(28,969)	(2,379)
Total Comprehensive Income (Loss)	$ (1,453)	$121,464	$ 98,567

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

(1) Summary of the Business and Significant Accounting Policies

Nature of Business

PNM Resources, Inc. (the "Holding Company") is an investor-owned holding company of energy and energy related businesses. 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 marketing of electricity; transmission, distribution and sale of natural gas within the State of New Mexico and the sale and marketing of electricity in the Western United States. The Holding Company and its subsidiaries, including PNM, are herein after referred to as the "Company". 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 Holding Company, the Holding Company became the parent company of PNM. Prior to the share exchange, the Holding Company had existed as a subsidiary of PNM. The new parent company began trading on the New York Stock Exchange under the same PNM symbol beginning on December 31, 2001.

Presentation

The Notes to Consolidated Financial Statements of the Company are presented on a combined basis. The Holding Company assumed substantially all of the corporate activities of PNM on December 31, 2001. These activities are billed to PNM on a cost basis to the extent they are for the corporate management of PNM. In January 2002, Avistar and certain inactive subsidiaries of PNM were transferred by way of a dividend to the Holding Company pursuant to an order from the New Mexico Public Regulation Commission ("PRC"). Readers of the Notes to Consolidated Financial Statements should assume that the information presented applies to the consolidated results of operations and financial position of both the Holding Company and its subsidiaries and PNM, except where the context or references clearly indicate otherwise. Discussions regarding specific contractual obligations generally reference the company that is legally obligated. In the case of contractual obligations of PNM, these obligations are consolidated with the Holding Company and its subsidiaries under generally accepted accounting principles ("GAAP"). Broader operational discussions refer to the Company.

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 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 FERC, and the PRC and its predecessor. These "regulatory assets" and "regulatory liabilities" are enumerated and discussed in Note 3.

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 as recovery is no longer probable. 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. 144, *"Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of"* ("SFAS 144"). 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.

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 ("EITF") 90-15, *"Impact of Non-Substantive Lessors, Residual Value Guarantees and Other Provisions in Leasing Transactions."* All significant intercompany transactions and balances have been eliminated. There were no intercompany transactions between the Holding Company and PNM in 2001 and 2000, except the dividend, consolidation of PVNGS capital trust and minority interest described in Note 5.

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Financial Statement Preparation

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.

Cash and Cash Equivalents

All liquid investments with maturities of three months or less at the date of purchase are considered cash equivalents.

Utility Plant

Utility plant, with the exception of Palo Verde Nuclear Generating Station ("PVNGS") Unit 3, a portion San Juan Generating Station ("SJGS") Unit 4 and PNM'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 New Mexico 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 by $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, PNM wrote down $131.6 million of its owned interest in Units 1 and 2.

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 regulated property in the normal course of business are credited or charged to the accumulated provision for depreciation.

Allowance For Funds Used During Construction ("AFUDC")

The calculation of AFUDC is only permitted if a rate order exists that provides recovery. AFUDC uses a weighted average cost of capital. PNM did not calculate AFUDC on construction projects in 2002, 2001 or 2000.

Capitalized Interest

SFAS 34, *"Capitalization of Interest Costs"* requires that interest cost be capitalized as part of the historical cost of acquiring certain assets and is calculated using only the cost of borrowing. Under GAAP, interest can only be capitalized on non-SFAS 71 assets. PNM capitalizes interest on its generation projects not included in rate base that are under construction in which ground has been broken for the project, i.e. construction activities are underway. The interest cost to be capitalized is theoretically that portion of interest expense that could have been avoided if construction expenditures were not made. The rate used for capitalization is the rate for borrowings specific to the project. If there are no specific borrowings, the weighted average borrowing rate for the Company is used. PNM has not borrowed any funds specifically for any projects; therefore interest is being capitalized at the overall weighted average borrowing rate of 6.6%. PNM's capitalized interest was $6.4 million in 2002. No interest was capitalized in 2001 or 2000.

Inventory

Inventory consists principally of materials and supplies, natural gas held in storage for eventual resale, and coal held for use in electric generation.

Generally, materials and supplies include the costs of transmission, distribution and generating plant materials. Materials and supplies are charged to inventory when purchased and are expensed or capitalized as appropriate when issued. Materials and supplies are valued using an average costing method. Obsolete materials and supplies are immediately expensed when identified.

Gas in underground storage is valued using a weighted-average inventory method. Withdrawals are charged to sales service customers through the Purchased Gas Adjustment Clause ("PGAC"). Adjustments to gas in underground storage due to migration are charged to the PGAC and are based on a PRC pre-approved percentage of injections.

Coal is valued using a rolling weighted average costing method that is updated based on the current period cost per tons. Periodic aerial surveys are performed and any necessary adjustments are expensed as identified.

Inventories consisted of the following at December 31, *(in thousands)*.

	2002	2001
Coal	$12,678	$12,960
Gas in underground storage	2,001	3,664
Materials and supplies	22,551	19,859
	$37,230	$36,483

Investments

The Company's investments are comprised of 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 are in the custody of 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, 2002, 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 stockholders' 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 PGAC administered by the PRC. The Company recognizes this adjustment when PNM is permitted to bill under PRC guidelines.

However, the determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. The cycle meter reading results in unbilled consumption between the date of the last meter reading in a particular month and the end of the month. Unbilled electric revenue is estimated each month based on the daily generation volumes, estimated customer usage by class, weather factors, line losses and applicable customer rates based on regression analysis reflecting significant historical trends and experience.

The Company purchases gas on behalf of sales-service customers while other marketers or producers purchase gas on behalf of transportation service customers. The Company collects a cost of service revenue for the transportation, delivery, and customer service provided to these customers. Sales-service tariffs are subject to the terms of the PGAC while transportation service customers are metered and billed on the last day of the month. Therefore, the Company estimates unbilled decatherms and cost of service revenues for sales-service customers only.

The unbilled decatherms are based on consumption estimates and the associated cost of service revenue for the period. A cycle bill contains an amount for both the current period's consumption and the prior period's consumption. The unbilled portion that is recorded is estimated as a percentage of the next month's budgeted cycle billings. These budgets are prepared using historical data adjusted for known trends, including prior period consumption. Adjustments are also made to the budgeted cycle billings for weather variations above or below normal, customer growth, and any pricing changes by customer rate and revenue class. Any differences between the estimate and the actual cycle billings are recorded in the month billed.

The Company's Generation and Marketing 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 merchant energy 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 Marketing Operations transactions that are net settled, are recorded gross in operating revenues and fuel and purchased power expense.

The Company enters into merchant energy 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 derivative energy contracts that are not deemed normal purchases and sales or hedges are recognized as adjustments to Generation and Marketing

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Operations operating revenues. The market prices used to value these 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.

However, in accordance with the Western Systems Power Pool contract, these revenues are billed in the month subsequent to their delivery. Consequently, wholesale power marketing revenues for the last month in any reporting period are unbilled when reported.

Unbilled utility revenues and unbilled wholesale power marketing revenues are combined and specifically identified in the consolidated balance sheets.

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:

	2002	2001	2000
Electric plant	3.42%	3.39%	3.42%
Gas plant	3.02%	3.21%	3.28%
Common plant	7.34%	6.92%	6.75%

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.

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 early 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 EITF reached consensus on EITF Issue No. 98-10 which requires that energy trading contracts 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. (See Note 16 for further discussion).

The Company implemented SFAS 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. All energy contracts marked-to-market under EITF 98-10 were subject to mark-to-market accounting upon adoption of SFAS 133 (see further discussion in Note 16).

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.

SFAS 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 only (see further discussion in Note 16).

At December 31, 2002 the Company had three stock-based employee compensation plans of which options continue to be granted under only two of the plans. These plans are described more fully in Note 10. 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):

	Year Ended December 31,		
	2002	2001	2000
Net earnings: (available for common)	$ 63,686	$149,847	$100,360
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(4,422)	(3,351)	(3,578)
Pro forma net earnings	$ 59,264	$146,496	$ 96,782
Earnings per share:			
Basic – as reported	$ 1.63	$ 3.83	$ 2.54
Basic – pro forma	$ 1.51	$ 3.74	$ 2.45
Diluted – as reported	$ 1.61	$ 3.77	$ 2.53
Diluted – pro forma	$ 1.50	$ 3.69	$ 2.44

Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, *"Accounting for Income Taxes"* ("SFAS No. 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 approved rates include the tax effects of the majority of these 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 evaluates the carrying value of regulatory and tangible long-lived assets in relation to their future undiscounted cash flows to assess recoverability in accordance with SFAS 144. 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.

Change in Presentation

Certain prior year amounts have been reclassified to conform to the 2002 financial statement presentation.

(2) Segment Information

As it currently operates, the Company's principal business segments are Utility Operations, which include Electric Services ("Electric") and Gas Services ("Gas"), Generation and Marketing Operations ("Generation and Marketing") and Unregulated Operations ("Unregulated"). 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

PNM provides retail electric service, regulated by the PRC, to a large area of north central New Mexico, including the cities of Albuquerque and Santa Fe, and certain other areas of New Mexico. PNM 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 Generation and Marketing. Intersegment purchases from Generation and Marketing 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 delivery and production that includes certain generation assets that are part of Generation and Marketing plus a rate of return.

Gas

PNM's gas operations distribute natural gas to most of the major communities in New Mexico, including Albuquerque and Santa Fe. PNM's customer base includes both sales-service customers and transportation-service customers. Customer rates for gas service are set by the PRC based on the recovery of the cost of delivering gas plus a rate of return, with the cost of gas procured for customers being passed through to customers through a Purchased Gas Adjustment Clause ("PGAC").

In 2000 and the first quarter of 2001, Generation and Marketing procured its gas fuel supply from Gas. Beginning with the second quarter of 2001, Generation and Marketing began procuring its gas supply independently of Gas and contracted with Gas for transportation services only.

GENERATION AND MARKETING OPERATIONS

Generation and Marketing serves four principal markets. These include sales to PNM's Utility Operations to cover retail electric demand, sales to firm-requirement 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, PNM purchases power in the open market. As of December 31, 2002, the total net generation capacity of facilities owned or leased by PNM was 1,742 MW, including a 132 MW power purchase contract accounted for as an operating lease.

UNREGULATED AND OTHER

The Holding 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 immaterial corporate activities and eliminations. The immaterial corporate activities were assumed by the Holding Company on December 31, 2001. Avistar was transferred by a way of a dividend to the Holding Company by its subsidiary, PNM.

RISKS AND UNCERTAINTIES

The Company's future results may be affected by changes in regional economic conditions; the outcome of labor negotiations with union employees; fluctuations in fuel, purchased power and gas prices; the actions of utility regulatory commissions; changes in law and environmental regulations; the performance of PNM's generating units and the success of any generation expansion and external factors such as the weather, including the drought conditions currently prevalent in New Mexico. In the early 1990s, federal and state policymakers began investigating and implementing major reforms regarding the public utility industry, designed to transform electric generation into a competitive business separate from the regulated monopoly businesses of transmission and distribution, at least on a functional basis. These reforms introduced new risks into the Company's business which had the potential to impact future results, such as the Company's ability to recover 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. However, as a result of the energy crisis in California and the Global Electric Agreement (see Note 12), plans for restructuring the industry are undergoing fundamental review. Legislation to repeal existing law providing for customer choice and competition in retail electric power supplies, currently scheduled to commence in 2007, is being considered in the 2003 session of the New Mexico Legislature. This legislation, SB 718, has passed the Senate on a 37-2 vote and is currently awaiting action in the House of Representatives. Any reforms that may be made to existing plans for restructuring the industry will also affect the Company's future results. In addition to the fate of retail electric competition in New Mexico, the Company's future results will continue to be affected on the wholesale side by the market price of electricity and natural gas costs, and the results of federal reforms regarding the wholesale market and transmission service.

Summarized financial information by business segment for 2002, 2001 and 2000 is as follows:

	Utility					
	Electric	Gas	Total	Generation and Marketing	Unregulated and Other	Consolidated
			(In thousands)			
Twelve Months Ended 2002:						
Operating revenues:						
External customers	$ 570,089	$ 272,118	$ 842,207	$ 325,385	$ 1,404	$ 1,168,996
Intersegment revenues	707	-	707	348,935	(349,642)	-
Depreciation and amortization	34,025	20,964	54,989	43,837	3,583	102,409
Interest income	436	436	872	1,995	42,087	44,954
Interest charges	23,640	13,546	37,186	16,625	7,601	61,412
Operating income (loss)	60,449	18,652	79,101	24,737	(2,064)	101,774
Income tax expense	21,731	4,351	26,082	4,596	2,353	33,031
Segment net income	33,163	6,640	39,803	7,013	17,456	64,272
Total assets	761,694	505,692	1,267,386	1,124,387	635,134	3,026,907
Gross property additions	56,698	46,676	103,374	116,447	20,404	240,225
Twelve Months Ended 2001:						
Operating revenues:						
External customers	$ 559,226	$ 385,418	$ 944,644	$ 1,393,635	$ 1,538	$ 2,339,817
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	596	2,222	3,215	43,304	48,741
Interest charges	19,868	11,807	31,675	28,282	4,883	64,840
Operating income (loss)	57,417	17,730	75,147	150,565	(3,035)	222,677
Income tax expense (benefit)	23,679	3,469	27,148	73,525	(19,610)	81,063
Segment net income (loss)	36,130	5,498	41,628	112,194	(3,389)	150,433
Total assets	749,948	469,410	1,219,358	1,430,917	263,513	2,913,788
Gross property additions	74,316	48,978	123,294	126,605	14,945	264,844

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	Utility			Generation	Unregulated	
	Electric	Gas	Total	and Marketing	and Other	Consolidated
			(In thousands)			
Twelve Months Ended 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	41,559	26	93,059
Interest income	1,158	9	1,167	1,708	45,820	48,695
Interest charges	17,771	11,089	28,860	37,058	(476)	65,442
Operating income (loss)	56,351	19,104	75,455	78,451	(21,432)	132,474
Income tax expense	27,419	7,588	35,007	28,337	11,002	74,346
Segment net income	38,999	11,208	50,207	49,372	1,367	100,946
Unaudited:						
Total assets	698,979	516,430	1,215,409	1,400,910	277,914	2,894,233
Gross property additions	51,815	40,418	92,233	53,025	1,620	146,878

(3) 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:

	2002	2001
	(In thousands)	
Assets:		
Current:		
PGAC	$ 23,907	$ 9,065
Gas Take-or-Pay Costs	120	1,408
Subtotal	24,027	10,473
Deferred:		
Deferred Income Taxes	33,321	33,632
Loss on Reacquired Debt	5,978	6,798
Other	2,312	710
Subtotal	41,611	41,140
Stranded and Transition Assets	154,672	154,227
(see discussion below)		
Total Deferred Assets	196,283	195,367
Total Assets	220,310	205,840
Liabilities:		
Deferred:		
Deferred Income Taxes	(38,941)	(41,915)
Unrealized loss on PVNGS decommissioning trust	(3,813)	(2,137)
Gain on Reacquired Debt	(1,495)	(1,640)
Other	(1,755)	(2,119)
Subtotal	(46,004)	(47,811)
Stranded and Transition Liabilities	(20,152)	(20,647)
(see discussion below)		
Total Deferred Liabilities	(66,156)	(68,458)
Net Regulatory Assets	$154,154	$ 137,382

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 of such 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.

Approximately $135 million of costs associated with the unregulated businesses under the Restructuring Act, as amended, 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 Marketing Operations has discontinued SFAS 71 and adopted SFAS 101. On October 10, 2002, the Company and several other parties signed the Global Electric Agreement which provides for a five year rate path for the Company's New Mexico retail electric customers beginning in September 2003 and seeks a repeal of a majority of the Restructuring Act, as amended. (See Note 12 for further discussion.) As a result, the Company expects to re-apply SFAS 71 to certain Generation and Marketing Operations upon approval by the PRC of the Global Electric Agreement.

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 costs that were not a component of retail ratemaking. The Company may recover the remaining $100 million of costs associated with coal mine decommissioning that are attributed to New Mexico retail customers in its Global Electric Agreement which provides for a 17-year recovery of these costs beginning in September 2003.

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. 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. (See Note 12 "Global Electric Agreement" for further developments.)

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, or if further restructuring will take place under any repeal of the Restructuring Act.

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

	2002	[illegible]
	(In thousands)	
Assets:		
Transition costs	$ 16,720	$ 15,908
Mine reclamation costs	100,877	100,877
Deferred income taxes	35,708	35,775
Loss on reacquired debt	1,367	1,667
Subtotal	154,672	154,227
Liabilities:		
Deferred income taxes	(14,137)	(14,163)
PVNGS prudence audit	(4,682)	(5,058)
Settlement due customers	(1,325)	(1,408)
Gain on reacquired debt	(8)	(18)
Subtotal	(20,152)	(20,647)
Net Stranded cost and transition cost	$134,520	$133,580

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, except for the transition costs (see further discussion in Note 12).

(4) Capitalization

Common Stock

The number of authorized shares of common stock of the Holding Company is 120 million shares with no par value. The number of shares outstanding was 39,117,799 as of December 31, 2002 and 2001. The only change to common stock of the Holding Company in 2002 was for the exercise of stock options of $1.8 million. In 2001, the exercise of stock options of $2.2 million was the only change to additional paid-in-capital of PNM. There were no changes to common stock or additional-paid-in-capital of PNM in 2002.

The declaration of common dividends is dependent upon a number of factors including the ability of the Holding Company's subsidiaries to pay dividends. Currently, PNM is the Holding 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. Conditions imposed by the PRC 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 June 10, 2002, the PNM Board of Directors declared a dividend of $24.7 million, which was paid on June 28, 2002.

On February 18, 2003, the Holding Company's Board of Directors approved a 4.5 percent increase in the common stock dividend. The increase raised the quarterly dividend to $0.23 per share, for an indicated annual dividend of $0.92 per share.

On August 8, 2000, PNM's Board of Directors approved a plan to repurchase up to $35 million of PNM's 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.

Cumulative Preferred Stock

No Holding Company preferred stock is outstanding. The Holding Company's restated articles of incorporation authorize 10 million shares of preferred stock, which may be issued without restriction. The number of authorized shares of PNM cumulative preferred stock is 10 million shares. PNM has 128,000 shares, 1965 Series, 4.58%, par 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 the 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

On March 11, 1998, PNM modified its 1947 Indenture of Mortgage and Deed of Trust so that no future bonds can be issued under the mortgage. While first mortgage bonds continue to serve as collateral for Pollution Control Bonds ("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. In 1999, PNM retired $31.6 million of its 7.10% SUNs 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 December 20, 2002, the Holding Company acquired the equity interest of the grantor trust that owns 60% of the EIP transmission line and related activities. As a result, $26.1 million of related debt was brought on to the consolidated balance sheet. This debt was previously disclosed and reported as off balance sheet debt. The EIP debt bears interest at the rate of 10.25%, requires semi-annual principal and interest payments and matures on April 1, 2012.

Revolving Credit Facility and Other Credit Facilities

At December 31, 2002, PNM had a $195 million unsecured revolving credit facility (the "Facility") with an expiration date of December 18, 2003. PNM must pay commitment fees of 0.2% per year on the unused amount of the Facility. PNM must also pay a utilization fee of .125% for all borrowings in excess of 33% of the committed amount. PNM also had $20 million in local lines of credit. In addition, the Holding Company has a $20 million reciprocal borrowing agreement with PNM and $15 million in local lines of credit.

There were $150 million in outstanding borrowings bearing interest at a weighted average interest rate of 2.759% under the Facility as of December 31, 2002. On January 31, 2003, this amount was refunded at an interest rate of 2.325%. PNM was in compliance with all covenants under the Facility.

(5) 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 Note 4), 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 $13.2, $12.4 and $10.7 million in 2002, 2001 and 2000, respectively. The summary of PNM's future minimum operating lease payments below reflects the net cash outflow related to the PVNGS leases.

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PNM's other significant operating lease obligations include a leased interest in 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. On December 20, 2002, the Holding Company acquired the equity interest of the grantor trust, which owns 60% of the EIP transmission line and related activities.

Future minimum operating lease payments (in thousands) at December 31, 2002 are:

2003	$ 28,216
2004	28,280
2005	29,936
2006	30,753
2007	31,638
Later years	298,150
Total minimum lease payments	$ 446,973

Operating lease expense, inclusive of the net PVNGS lease payment, was approximately $34.9 million in 2002, $32.7 million in 2001 and $28.5 million in 2000. Aggregate minimum payments to be received in future periods under non-cancelable subleases are approximately $4.5 million.

(6) Fair Value of Financial Instruments

The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Although management uses its best judgment in estimating the fair value of these financial instruments, there are inherent limitations in any estimation technique. Therefore, the fair value estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current transaction.

Fair value is based on market quotes provided by the Company's investment bankers and trust advisors. The market prices used to value PNM's mark-to-market energy portfolio are based on closing exchange prices and over-the-counter quotations.

The carrying amounts reflected on the consolidated balance sheets approximate fair value for cash, temporary instruments, receivables, and payables due to the short period of maturity. The carrying amount and fair value of the Company's financial instruments (including current maturities) at December 31 are:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-Term Debt	$ 980,092	$1,027,435	$ 953,884	$ 973,569
Investment in PVNGS Lessors' Notes	$ 368,010	$ 436,345	$ 387,347	$ 417,828

The amortized cost, gross unrealized gain and losses and estimated fair value of investments in available-for-sale securities at December 31 are as follows:

	2002			
	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
	(In thousands)			
Available-for-sale:				
Equity securities	$ 32,643	$ 4,134	$ (1,514)	$ 35,263
Mortgage-backed securities	33,145	410	(93)	33,462
Corporate bonds	32,466	438	(19)	32,885
Municipal bonds	21,229	1,394	(24)	22,599
U.S. Government securities	12,725	702	-	13,427
Other investments	14,716	-	-	14,716
	$ 146,924	$ 7,078	$ (1,650)	$ 152,352

	2001			
	Amortized Cost	Unrealized Gains	Unrealized Losses	Fair Value
	(In thousands)			
Available-for-sale:				
Mortgage-backed securities	$ 60,145	$ 92	$ (250)	$ 59,987
Equity securities	29,965	8,700	(1,595)	37,070
U.S. Government securities	36,523	282	(157)	36,648
Corporate bonds	32,273	43	(143)	32,173
Municipal bonds	21,420	597	(153)	21,864
Other investments	31,170	-	-	31,170
	$ 211,496	$ 9,714	$ (2,298)	$ 218,912

At December 31, 2002, the available-for-sale securities held by the Company had the following maturities:

	Amortized Cost	Fair Value
	(In thousands)	
Within 1 year	$ 6,198	$ 6,203
After 1 year through 5 years	41,020	41,838
After 5 years through 10 years	4,343	4,511
Over 10 years	48,004	49,821
Equity securities	32,643	35,263
Other investments	14,716	14,716
	$ 146,924	$ 152,352

The proceeds and gross realized gains and losses on the disposition of available-for-sale investments are shown in the following table. Realized gains and losses are determined by specific identification.

	2002	2001	2000
	(In thousands)		
Proceeds from sales	$219,880	$80,943	$59,323
Gross realized gains	2,537	3,077	8,516
Gross realized losses	(7,624)	(7,476)	(5,341)

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electricity 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 wholesale electricity sales 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, 2002 and 2001 was $18.7 million and $7.5 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.

PNM purchased gas options, a type of hedge, to protect its natural gas customers from the risk of price fluctuation during the 2002-2003 heating season. PNM expended $6.0 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 2002 through February 2003 in equal allotments of $1.2 million.

Generation and Marketing

Commencing in 2000, the Company's Generation and Marketing 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 Marketing 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 Contracts

For the year ended December 31, 2002, the Company's wholesale electric marketing operations settled forward contracts for the sale of electricity that generated $43.9 million of electric revenues by delivering 1.2 million MWh. The Company purchased $74.5 million or 1.4 million MWh of electricity to support these contractual sales and other open market sales opportunities. For the year ended December 31, 2001, the Company's wholesale electric marketing operations settled forward contracts for the sale of electricity that generated $77.9 million of electric revenues by delivering 2.1 million MWh. The Company purchased $76.7 million or 1.9 million MWh of electricity to support these contractual sales and other open market sales opportunities.

As of December 31, 2002, the Company had open contract positions to buy $59.7 million and to sell $56.1 million of electricity. At December 31, 2002, the Company had a gross mark-to-market gain (asset position) on these forward contracts of $4.8 million and gross mark-to-market loss (liability position) of $5.7 million, with net mark-to-market loss (liability position) of $0.9 million. The change in mark-to-market valuation is recognized in earnings each period.

In addition, the Company's Generation and Marketing Operations entered into forward physical contracts for the sale of the Company's electric capacity in excess of its retail and wholesale firm requirement needs, including reserves, or the purchase for retail 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 retail needs when the cost of purchased power is less than the incremental cost of its generation. At December 31, 2002, the Company had open forward positions classified as normal sales of electricity of $141 million and normal purchases of electricity of $99 million.

The Company's Generation and Marketing Operations, including both firm commitments and other merchant sale 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 retail 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 at December 31, 2002, and an additional $136 million that become callable at a premium in August 2003. PNM intends to refinance these bonds, assuming the interest rate of the refinancing does not exceed the current interest rate of the bonds, and has hedged the entire planned refinancing. The Company received regulatory approval to refund the tax-exempt bonds on October 29, 2002. This approval is effective for one year. In order to take advantage of current low interest rates, PNM entered into five forward starting interest rate swaps in the fourth quarter of 2001 and the first quarter of 2002. 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 rate on the refinancing to 4.95% plus an adjustment for PNM's and the industry's credit rating. PNM's assessment of hedge effectiveness is based on changes in the hedge 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. For the year ended December 31, 2002, PNM recognized $0.4 million of hedge ineffectiveness in earnings. At December 31, 2002, the fair market value of these derivative financial instruments was approximately $18.4 million unfavorable to the Company.

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 benchmark. The five forward starting interest rate swaps have a termination date of May 15, 2003 for a combined notional amount of $182.0 million. There were no fees on the transaction, as they are imbedded in the rates, and the transaction will be 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.

(7) 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:

	2002		
	(In thousands, except per share amounts)		
Basic:			
Net Earnings	$ 64,272	$ 150,433	$ 100,946
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 63,686	$ 149,847	$ 100,360
Average Number of Common Shares Outstanding	39,118	39,118	39,487
Net Earnings per Share of Common Stock (Basic)	$ 1.63	$ 3.83	$ 2.54
Diluted:			
Net Earnings	$ 64,272	$ 150,433	$ 100,946
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 63,686	$ 149,847	$ 100,360
Average Number of Common Shares Outstanding	39,118	39,118	39,487
Diluted Effect of Common Stock Equivalents (a)	325	613	223
Average Common and Common Equivalent Shares Outstanding	39,443	39,731	39,710
Net Earnings per Share of Common Stock (Diluted)	$ 1.61	$ 3.77	$ 2.53

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out of-the-money options of 1,602,277 and 105,336 for the years ended December 31, 2002 and 2000, respectively. There were no anti-dilutive common stock equivalents in 2001.

(8) Income Taxes

Income taxes from net earnings consist of the following components:

	2002	2001	2000
		(In thousands)	
Current Federal income tax	$ (9,327)	$ 97,661	$ 41,666
Current state income tax	(1,780)	21,220	13,726
Deferred Federal income tax	38,413	(28,967)	19,729
Deferred state income tax	8,856	(5,712)	2,368
Amortization of accumulated investment tax credits	(3,131)	(3,139)	(3,143)
Total income taxes	$ 33,031	$ 81,063	$ 74,346
Charged to operating expenses	$ 20,887	$ 88,769	$ 53,964
Charged to other income and deductions	12,144	(7,706)	20,382
Total income taxes	$ 33,031	$ 81,063	$ 74,346

The Company's provision for income taxes 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:

	2002	2001	2000
		(In thousands)	
Federal income tax at statutory rates	$ 34,056	$ 81,024	$ 61,352
Investment tax credits	(3,131)	(3,139)	(3,143)
Depreciation of flow-through items	2,112	2,249	2,250
Gains on the sale and leaseback of PVNGS Units 1 and 2	(527)	(527)	(527)
Equity income from passive investments	-	(1,180)	
Annual reversal of deferred income taxes accrued at prior tax rates	(1,963)	(1,963)	(2,477)
Valuation reserve	-	(6,552)	6,552
Research and development credit	(551)		
Affordable housing credit	(947)		
State income tax	4,715	10,706	8,343
Other	(733)	445	1,996
Total income taxes	$ 33,031	$ 81,063	$ 74,346
Effective tax rate	33.95%	35.02%	42.41%

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

	2002	2001
	(In thousands)	
Deferred Tax Assets:		
Nuclear decommissioning costs	$ 32,192	$ 28,138
Regulatory liabilities related to income taxes	37,656	40,594
Minimum pension liability	56,008	19,924
Net operating loss	-	29,451
Other	57,373	59,049
Total deferred tax assets	183,229	177,156
Deferred Tax Liabilities:		
Depreciation	216,425	189,157
Investment tax credit	41,583	44,714
Fuel costs	11,749	5,515
Regulatory assets related to income taxes	67,744	68,086
Other	27,043	19,263
Total deferred tax liabilities	364,544	326,735
Valuation allowance	-	29,451
Accumulated deferred income taxes, net	$181,315	$179,030

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	$ 2,285
Change in tax effects of income tax related regulatory assets and liabilities	(2,596)
Tax effect of mark-to-market on investments available for sale	8,365
Tax effect of excess pension liability	36,084
Deferred income tax expense for the period	$ 44,138

The Company has no net operating loss carryforwards as of December 31, 2002.

The Company defers investment tax credits related to rate regulated assets and amortizes them over the estimated useful lives of those assets.

All federal income tax years prior to 1997 are closed, and most issues for 1997 through 1998 have been resolved. No years are currently under examination by the IRS.

There are no material differences between the provision for income taxes and deferred income taxes between the Company and PNM.

(9) Pension and Other Post-retirement 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. In addition, in January 2002, the Company made an aggregate contribution of $23.5 million to fund pension and other post-retirement benefit plans. An additional aggregate contribution of $1.1 million was made in September 2002 and $1.5 million in December 2002. The Company contributions to the 401(k) plan consist of a 3% non-matching contribution, and a 75% match on the first 6% contributed by the employee on a before-tax basis. The Company contributed $9.5, $9.0 and $8.9 million in the years ended December 31, 2002, 2001 and 2000, 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 2002	Pension Benefits 2001
Change in Projected Benefit Obligation:		
Projected benefit obligation at beginning of year	$ 373,434	$ 321,429
Service cost	5,539	5,544
Interest cost	27,238	25,758
Amendments	-	3,560
Actuarial gain	41,192	36,143
Benefits paid	(20,518)	(19,000)
Projected benefit obligation at end of period	426,885	373,434
Change in Plan Assets:		
Fair value of plan assets at beginning of year	339,838	389,827
Actual return on plan assets	(20,207)	(30,989)
Contribution	20,000	-
Benefits paid	(20,518)	(19,000)
Fair value of plan assets at end of year	319,113	339,838
Funded Status	(107,772)	(33,596)
Unrecognized net actuarial loss	144,328	48,432
Unrecognized prior service cost	3,109	3,437
Prepaid pension cost	$ 39,665	$ 18,273
The amounts recognized in the Consolidated Balance Sheet consist of:		
Accrued benefit liability	$(107,772)	$ (33,596)
Intangible asset	3,109	3,437
Accumulated other comprehensive income	144,328	48,432
Net amount recognized	$ 39,665	$ 18,273
Weighted - Average Assumptions as of September 30,		
Discount rate	6.75%	7.50%
Expected return on plan assets	9.00%	7.75%

	Pension Benefits 2002	Pension Benefits 2001	Pension Benefits 2000
Components of Net Periodic Benefit Cost:			
Service cost	$ 5,539	$ 5,544	$ 6,491
Interest cost	27,238	25,758	23,572
Expected return on plan assets	(34,497)	(29,488)	(30,923)
Amortization of net gain	-	(847)	-
Amortization of transition obligation	-	(1,158)	(1,164)
Amortization of prior service cost	326	34	34
Net periodic pension benefit	$ (1,394)	$ (157)	$ (1,990)

Other Post-retirement 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	
	[illegible]	[illegible]
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$ 109,408	$ 81,711
Service cost	2,694	2,644
Interest cost	8,082	7,906
Amendments	(31,960)	-
Unrecognized actuarial loss	32,876	20,500
Expected benefit paid	(3,304)	(3,353)
Benefit obligation at end of period	117,796	109,408
Change in Plan Assets:		
Fair value of plan assets at beginning of year	42,132	44,694
Actual return on plan assets	(6,478)	(5,161)
Employer contribution	7,429	6,748
Benefits paid	(2,881)	(3,553)
Fair value of plan assets at end of year	40,202	42,728
Funded Status	(77,594)	(66,680)
Unrecognized net transition obligation	18,171	19,988
Unrecognized net actuarial loss	74,048	31,763
Unrecognized prior service cost	(31,960)	-
Accrued post-retirement costs	$ (17,335)	$ (14,929)
Weighted – Average Assumptions as of September 30,		
Discount rate	6.75%	7.50%
Expected return on plan assets	9.00%	8.25%

		Other Benefits	
	[illegible]	[illegible]	[illegible]
Components of Net Periodic Benefit Cost:			
Service cost	$ 2,694	$ 2,644	$ 1,053
Interest cost	8,082	7,906	5,428
Expected return on plan assets	(4,505)	(3,412)	(3,572)
Amortization of net loss	1,320	799	-
Amortization of transition obligation	1,817	1,817	1,817
Net periodic post-retirement benefit cost	$ 9,408	$ 9,754	$ 4,726

The effect of a 1% increase in the health care trend rate assumption would increase the accumulated post-retirement benefit obligation as of September 30, 2002, by approximately $21.3 million and the aggregate service and interest cost components of net periodic post-retirement benefit cost for 2002 by approximately $2.0 million. The health care cost trend rate is expected to decrease to 6.0% by 2011 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 for this program, as of the plan valuation date of September 30, 2002 and 2001, was $19.0 million and $17.7 million, respectively. As of December 31, 2002 and 2001, the Company has recognized an additional minimum liability of $4.1 million and $2.8 million, respectively, for the amount of unfunded accumulated benefits in excess of accrued pension costs. The net periodic cost for 2002, 2001 and 2000 was $1.7 million, $1.7 million and $1.9 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 $8.2 million (fair market value of $8.2 million) are presently in the trust. No additional funds have been provided to the trust since 1989.

(10) 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 at the close of business 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. All options vest upon death, disability, retirement, impaction or involuntary termination other than for cause. 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 ("PEP"), became effective with the formation of the Holding Company on December 31, 2001. The PEP 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 all awards under the PEP may not exceed 2.5 million, subject to adjustment under certain circumstances defined in the PEP. The number of shares of stock subject to 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. 855,000 options and 1,620 restricted stock rights were awarded in 2002. Under the PEP, 2,500 options were exercised in 2002. The number of options and restricted stock rights outstanding as of December 31, 2002 were 847,500 and 1,620, respectively.

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 2002 under the DRP was 35,000 shares with an exercise price of $27.35 and 10,000 with an exercise price of $20.15 and in 2001 6,000 shares with an exercise price of $22.61. Under the DRP plan, vesting occurs on the date of the next annual meeting after the award. Under the DRP 5,000 options were exercised in 2002, 4,000 in 2001 and 4,000 in 2000. The number of options outstanding as of December 31, 2002, was 73,000. Restricted stock issuances were based on the fair market value of the Company's common stock at the close of business on the date of grant and vest ratably three years on the anniversary of the grant date. As of December 31, 2002, there was 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 at the close of business 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.

Fixed Options	2002 Shares	2002 Weighted Average Exercise Price	2001 Shares	2001 Weighted Average Exercise Price	2000 Shares	2000 Weighted Average Exercise Price
Outstanding at beginning of year	2,981,301	$19.100	3,336,221	$19.120	1,574,418	$18.207
Granted	901,620	$25.745	6,000	$22.610	2,078,500	$19.403
Exercised	356,132	$18.044	299,951	$19.610	296,027	$16.363
Forfeited	16,167	$21.390	60,969	$17.961	20,670	$17.320
Outstanding at end of year	3,510,622		2,981,301		3,336,221	
Options exercisable at year-end	1,525,345		981,197		916,263	
Options available for future grant	1,777,880		2,500,000		-	

The following table summarizes information about stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/02	Weighted Average Remaining Contractual Life	Weighted Average Exercise Prices	Number Exercisable At 12/31/02	Weighted Average Exercise Prices
DRP $5.50 - $27.35	73,000	8.363 years	$20.429	28,000	$11.876
PSP $11.50 - $24.313	2,588,502	6.888 years	$19.332	1,433,895	$20.644
PEP $ 0 - $28.22	849,120	9.246 years	$25.745	63,450	$25.943
	3,510,622	7.489 years	$20.906	1,525,345	$20.703

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

	2002	2001	2000
PEP	$ 7.42	$ -	$ 7.24
DRP	$ 7.03	$13.94	$ 6.98
Total fair market value of all options granted (in thousands)	$6,677	$ 83	$15,054

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

	2002	2001	2000
Dividend yield	3.43%	3.10%	2.98%
Expected volatility	33.62%	33.99%	26.43%
Risk-free interest rates	4.87%	5.38%	5.11%
Expected life	10.0 years	10.0 years	10.0 years

(11) Construction Program and Jointly-Owned Plants

The Company's construction expenditures for 2002 were approximately $240 million, including expenditures on jointly-owned projects. The Company's proportionate share of operating and maintenance expenses for the jointly-owned plants is included in operating expenses in the Consolidated Statements of Earnings.

At December 31, 2002, 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)	$710,027	$393,892	$ 9,046	46.3%
Palo Verde Nuclear Generating Station (Nuclear)*	$216,940	$ 67,732	$31,300	10.2%
Four Corners Power Plant Units 4 and 5 (Coal)	$118,509	$ 88,549	$ 6,113	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, 2002, 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")

The Company 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. The Company has a 10.2% undivided interest in PVNGS, with portions of its interests in Units 1 and 2 held under leases. (See Note 12 for additional discussion.)

(12) 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 power purchased agreement ("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 an operating lease for the rights to all the output of a new gas-fired generating plant for 20 years. The operating lease'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.

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.

On October 21, 2002, PNM entered into an agreement with FPL Energy LLC ("FPL"), a subsidiary of FPL Group, Inc., to develop a 200 MW wind generation facility in New Mexico. FPL Energy will build, own and operate the New Mexico Wind Energy Center ("NMWE"), consisting of 136 wind-powered turbines on a site in eastern New Mexico. PNM will buy all the power generated by the NMWE under a 25-year contract. Construction of the wind energy site began in January 2003. Construction on a facility of this size typically takes six to nine months to complete. PNM will ask the PRC to approve a voluntary tariff that will allow PNM retail customers to buy wind-generated electricity for a small monthly premium. Power from the facility not subscribed by PNM retail customers under the voluntary program will be sold on the wholesale market, either within New Mexico or outside the state.

In December 2002, PNM entered into a two-year contract to supply 80 MW of power to U.S. Navy facilities in San Diego, California. PNM began delivering power under the contract January 1, 2003. The contract runs through March 2005.

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 retail 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 Marketing was delivered by Gas. In the second quarter of 2001, Generation and Marketing began procuring its gas supply independent of the Company and contracting with the Utility Operations for transportation services only.

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Construction Commitment

PNM had previously committed to purchase five combustion turbines for a total cost of $151.3 million. The turbines are for planned power generation plants with an estimated cost of construction of approximately $370 million over the next five years depending on market conditions. PNM has expended $226 million as of December 31, 2002 of which $144 million was for equipment purchases. On June 27, 2002, Lordsburg, an 80 MW natural gas fired plant became fully operational and commenced serving the wholesale power market. Afton, a 141 MW simple cycle gas-fired plant, became fully operational on December 4, 2002. These plants are part of the Company's ongoing competitive strategy of increasing generation capacity over time to serve increasing retail load, sales under long-term contracts and other sales. These plants were not built to serve New Mexico retail customers and therefore are not currently, included in the rate base. However, it is possible that these plants may be needed in the future to serve the growing retail load. If so, these plants will have to be certified by the PRC and would then be included in the rate base.

Steam Generator Tubes

APS, as the operating agent of PVNGS, has encountered tube cracking in the steam generators and has taken, and will continue to take, remedial actions that it believes have slowed the rate of tube degradation. The projected service life of steam generators is assessed on an on-going basis. Two replacement steam generators will be installed in Unit 2 during its Fall 2003 refueling outage. The Company's share of the fabrication and installation costs (exclusive of replacement power costs) will be approximately $22 million.

The PVNGS participants ("Participants") have approved the purchase of replacement steam generators for Units 1 and 3. Preliminary work for the installation of the replacement steam generators has also been approved by the Participants. These actions will provide the Participants with options regarding the replacement of steam generators in Unit 1 and Unit 3. Unit 1 could be replaced as early as Fall 2005, should the Participants choose to do so. The Company estimates that its portion of the fabrication and installation costs and associated power upgrade modifications for Units 1 and 3, will be approximately $46 million over the period 2002-2003 (exclusive of replacement power costs), should installation of the ordered replacement steam generators be approved.

Terrorism Insurance

President Bush signed the Terrorism Risk Insurance Act of 2002 (TRIA) on November 26, 2002. Effective that date, to the extent covered by the act, endorsements excluding terrorism became null and void. Under the act, insurers are required to provide a premium quotation to the insured for terrorism coverage, with limits and deductibles similar to other coverage provided. The insured must accept and pay the premium, or reject the coverage within 30 days of receipt of the premium quotation. The Company has accepted all property and liability insurance offers of TRIA coverage. The Company also purchases $5,000,000 of non-TRIA terrorism coverage. Four Corners, in which the Company has a 13% interest in Units 4 and 5, has elected not to purchase TRIA or non-TRIA property insurance terrorism coverage.

PVNGS Liability and Insurance Matters

The PVNGS participants have financial protection 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 $300 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 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 million, with an annual payment limitation of approximately $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. The Price-Anderson Act, the federal law referred to above, was up for renewal in August 2002. Price-Anderson has been extended to December 31, 2003.

The PVNGS participants maintain "all-risk" (including nuclear hazards) insurance for damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.75 billion as of October 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 $5.1 million per year.

PVNGS Decommissioning Funding

PNM 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 2001 decommissioning cost study indicated that PNM's share of the PVNGS decommissioning costs, excluding spent fuel disposal, would be approximately $201 million (2001 dollars).

PNM provided an additional $10.7 million, $6.1 million and $3.9 million funding for the year ended December 31, 2002, 2001 and 2000 respectively, into the qualified and non-qualified trust funds. The estimated market value of the trusts for the year ended December 31, 2002 was approximately $63.2 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 domestic power reactors. Under the Waste Act, the DOE was to develop facilities necessary for the storage and disposal of spent nuclear fuel and to have the first facility in operation by 1998. The DOE has announced that such a repository cannot be completed before 2010.

The operator of PVNGS has capacity in existing fuel storage pools at PVNGS, which can accommodate all fuel expected to be discharged from normal operation of PVNGS until September 2003. The operator of PVNGS believes that it will be able to load dry storage casks and place the casks in the completed dry storage facility prior to September 2003. PNM currently estimates that it will incur approximately $41.0 million (in 2001 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. PNM accrues these costs as a component of fuel expense, meaning that the charges are accrued as the fuel is burned. The Company has accrued $1.0 million in 2002 for interim storage costs. 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 2003.

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 PNM line near the location. The explosion destroyed a small building and injured two persons who were working in the building. PNM's investigation indicates that the leak was an isolated incident likely caused by a combination of corrosion and increased pressure. PNM also cooperated with an investigation of the incident by the PRC's Pipeline Safety Bureau (the "Bureau"), which issued its report on March 18, 2002. The Bureau's report gave PNM notice of probable violations of the New Mexico Pipeline Safety Act and related regulations. PNM and the Bureau staff entered a compliance agreement addressing the probable violations and filed it with the PRC for approval on March 4, 2003. PNM agreed to undertake a list of twenty-four corrective actions, including internal policy changes, retraining employees and enhancing gas line monitoring. PNM has also agreed to voluntarily accelerate spending on pipeline replacement by more than $10.0 million and to commit an additional $1.8 million to development and implementation of systems to improve gas line management. The compliance agreement is pending before the PRC-. Two lawsuits against PNM by the injured persons along with several claims for property and business interruption damages have been resolved.

Global Electric Agreement

In November 2001, PNM began settlement negotiations with the PRC utility staff and intervenors in order to resolve its merchant plant filing and other matters. Discussions included the future framework for restructuring the electric industry in New Mexico under the Restructuring Act, a future retail electric rate path and PNM's merchant plant filing.

The year-long negotiations ended on October 10, 2002 with the filing of the Global Electric Agreement with the PRC. The Global Electric Agreement sets a rate path through 2007 and will resolve the issues surrounding industry deregulation in New Mexico and the PNM's merchant power strategy. The Global Electric Agreement was signed by PNM, the PRC Staff, the New Mexico Attorney General's Office, the New Mexico Industrial Energy Consumers, the City of Albuquerque, and the University of New Mexico. The United States Executive Agencies ("USEA") subsequently agreed to support the Global Electric Agreement as if they had signed it. The Global Electric Agreement also provides for the signatories to support passage of legislation concerning merchant plant activities and repeal of a majority of the Restructuring Act in the New Mexico Legislature.

Under the Global Electric Agreement, PNM will decrease retail electric rates 6.5% in two phases over the next three years. The first phase will be a 4.0% decrease, effective September 2003. The second phase will be a further 2.5% decrease from current rate levels, effective in September 2005. Rates would then be frozen at that level until the end of 2007. In addition, the risks and benefits of all wholesale electric sales, inure solely to the Company's shareholders until December 2007. Since the new rate Global Electric Agreement does not provide for a fuel cost adjustment, the lower fuel costs sought to be captured by shifting to underground mining for the coal supplies at SJGS will flow through to the Company's earnings largely offsetting the reduction in retail revenues.

PNM will be able to seek a general rate adjustment during the rate freeze period if complying with any new or changed environmental or tax law or regulation, or a new broader application of existing environmental or tax laws or regulations, would compromise its financial integrity. PNM also is permitted to capitalize all the reasonable costs of mandatory renewable energy resources, including an after-tax cost of capital of 8.64% to be recorded concurrently with the deferral of those costs.

PNM is authorized to recover in the stipulated rates and future retail rates, its New Mexico jurisdictional share of the decommissioning costs associated with the San Juan, La Plata and Navajo surface coal mines. PNM is allowed to recover up to $100 million of the costs, composed of approximately $69 million in surface coal mine reclamation costs, and approximately $31 million of contract buyout costs without being subject to prudence challenge by the signatories to the Global Electric Agreement. The costs will be amortized over 17 years commencing September 1, 2003 and in equal amounts each year thereafter. PNM cannot seek to recover a return on the unamortized reclamation costs, but could seek to recover a return on the unamortized contract buyout costs remaining as of December 31, 2007 in future rate adjustment proceedings.

The stipulated rates also provide for full recovery of nuclear decommissioning costs accrued in accordance with the estimates in the applicable decommissioning cost study during the rate freeze period for PNM's interests in PVNGS Units 1 and 2. The portion of SJGS Unit 4 previously treated as an excluded resource from PNM's New Mexico retail rates are included as a generation resource to serve PNM's New Mexico retail and wholesale firm requirements customers' load. PNM's contracts to purchase power from Tri-State, Delta Limited Partnership and firm power from Southwestern Public Service Company would also be included as generation resources to serve PNM's New Mexico retail and wholesale firm requirements customers' load until each contract expires under the Global Electric Agreement.

PRC approval or other authorization from the PRC is not required for PNM's merchant plant investment as long as PNM meets the following conditions: (a) PNM does not invest more than $1.25 billion in merchant plant; (b) PNM has an investment grade credit rating on a stand-alone basis and on a consolidated basis with the Holding Company; and (c) PNM spends at least $60 million per year in gas and electric utility, non-merchant plant infrastructure needed to maintain adequate and reliable service. No prior approval for merchant plant participation would be required and expedited PRC approval would be available for financing of merchant plant if certain specified financial conditions are met. If PNM's credit rating on a stand-alone or consolidated basis with the Holding Company falls below investment grade, however, approvals are needed for new merchant plant projects and for continuing to participate in merchant plant projects of more than a certain dollar value and under certain conditions.

PRC approval is not required for PNM to transfer any part of its interests in merchant plant or PVNGS Unit 3 from time to time to any other legal entity, provided that the following conditions are met: (a) PNM's debt to capital ratio will not exceed 65% after giving effect to the transfer and (b) PNM's investment grade status on a stand-alone basis and on a consolidated basis with the Holding Company will not be impaired by the transfer of merchant plant or PVNGS Unit 3 at the time of transfer.

PNM further agreed in the Global Electric Agreement that it will transfer all its interests in merchant plant out of PNM by January 1, 2010. PNM will accelerate the mandatory transfer to a date one year after PNM has completed expenditures of $1.25 billion on merchant plant. PNM may seek a variance from the PRC at any time prior to January 1, 2010 to extend or vacate the time or terms and conditions requiring the transfer but not beyond January 1, 2015.

Under the Global Electric Agreement, if merchant plant or PVNGS Unit 3 is transferred to a PNM affiliate, PNM's generation resources and the affiliate's generation resources may be jointly dispatched at the merchant affiliate's sole discretion until January 1, 2015. Joint dispatch of all utility, PVNGS Unit 3 or merchant plant resources would be terminable at any time between 2008 and 2015 at PNM's discretion, as long as the utility's dispatch capability is not impaired in any way.

PNM agreed to forego recovery of the costs incurred in preparing to transition to a competitive retail market in New Mexico. This will result in a one-time write-off of approximately $16.7 million, pre-tax, upon approval by the PRC of the Global Electric Agreement.

In the Global Electric Agreement, PNM, PRC utility staff and intervenors agreed to actively support the repeal of a majority of the Restructuring Act of 1999. If the repeal does not occur during the 2003 New Mexico Legislative Session, various modifications to the conditions of the Global Electric Agreement are triggered depending on how long repeal is delayed. SB 718 in the 2003 session would repeal the Restructuring Act as contemplated in the Global Electric Agreement. On February 28, 2003, SB 718 passed the Senate by a vote of 37-2. It is currently awaiting action in the House of Representatives.

In summary, the terms of this Global Electric Agreement and the Company's continuing efforts to control expenses offer significant benefits to both customers and shareholders in the form of lower rates, a predictable rate path, and the resolution of important issues affecting implementation of the Company's strategic plan over the next several years.

The Company is currently unable to predict the impact these proceedings may have on its plans to expand its generating capacity and its future financial condition and results of operations.

Other

There are various claims and lawsuits pending against the Company. 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 its 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.

The Company is involved in various legal proceedings in the normal course of business. The associated legal costs for these legal matters are accrued when incurred. It is also the Company's policy to accrue for legal costs expected to be incurred in connection with SFAS 5 legal matters when it is probable that a SFAS 5 liability has been incurred and the amount of expected legal costs to be incurred is reasonably estimable. These estimates include costs for external counsel professional fees.

(13) 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 such reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

The Company's recorded minimum liability estimated to remediate its identified sites was $8.5 million and $6.8 million as of December 31, 2002 and 2001, respectively. 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.

For the year ended December 31, 2002, 2001 and 2000, the Company spent $0.7 million, $1.7 million and $1.6 million respectively, for remediation. The majority of the December 31, 2002 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.

(14) Company Realignment

On August 22, 2002, the Company was realigned due to the changes in the electric industry and particularly, the negative impact on the Company's earnings and growth prospects from wholesale market uncertainty. The changes included consolidation of similar functions. A total of 85 salaried and hourly employees were notified of their termination as part of the realignment. In accordance with EITF 94-3, *"Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity"*, the Company incurred a liability of $8.8 million for severance and other related costs associated with the involuntary termination of employees, which was charged to operations in the quarter ended September 30, 2002 and is included in administrative and general in the consolidated statements of earnings for the year ended December 31, 2002. The Company paid $5.8 million through December 31, 2002.

(15) Other Income and Deductions

The following table details the components of other income and deductions for PNM Resources, Inc. and subsidiaries:

	Year Ended December 31,		
	2002	2001	2000
		(In thousands)	
Other Income:			
Interest and dividend income	$44,954	$48,742	$48,695
Settlement of lawsuit	-	-	13,750
Miscellaneous non-operating income	3,406	3,405	3,801
	$48,360	$52,147	$66,246

	2002	2001	2000
		(In thousands)	
Other deductions:			
Merger costs and related legal costs	$ (2,436)	$17,975	$6,700
Write-off of Avistar investments	-	13,089	4,100
Nonrecoverable coal mine decommissioning costs	-	12,979	-
Write-off of regulatory assets	-	11,100	-
Contribution to PNM Foundation	-	5,000	-
Transmission line project write-off	4,818	-	-
Miscellaneous non-operating deductions	9,924	7,114	1,150
	$12,306	$67,257	$11,950

(16) 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. SFAS 143 requires the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets that result from the acquisition, construction or development and or the normal operations of the long-lived assets. Retirement obligations associated with long-lived assets included within the scope of SFAS 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the standard, the asset retirement obligation ("ARO") liability is recognized at its fair value as incurred.

The recognition of an ARO results in an increase in the carrying cost of the long-lived asset, which will be amortized using a systematic and rationale basis over the remaining life of the related asset as depreciation expense. An ARO represents a future liability and, as a result, accretion expense will be accrued on this liability until such time as the obligation is satisfied. Accretion of the ARO liability due to the passage of time is recorded as an operating expense. If at the end of the asset's life the recorded liability differs from the actual settled obligation, the Company may incur a gain or loss that will be recognized at that time. The net difference between the amounts determined under SFAS 143 and the Company's previous method of accounting for such activities net of expected regulatory recovery, will be recognized as a cumulative effect of a change in accounting principle, net of related income taxes. The Company is currently calculating the liability associated with its AROs but does not believe there will be a material effect on continuing operations for the adoption of this standard.

Statement of Financial Accounting Standards No. 145, *"Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections"* ("SFAS 145"). In April 2002, the FASB issued SFAS 145. This statement updates and clarifies existing accounting pronouncements for the treatment of gains and losses from extinguishment of debt and eliminates an inconsistency between required accounting for sale-leaseback transactions and the required accounting for certain lease modifications that have similar economic effects as sale-leaseback transactions. In accordance with previous accounting standards, gains and losses from extinguishment of debt were classified as extraordinary gains and losses. The current statement permits gains and losses from extinguishment of debt to be classified as ordinary and included in income from operations, unless they are unusual in nature or occur infrequently and therefore included as an extraordinary item.

SFAS 145 is effective for fiscal years beginning after May 15, 2002 for the provisions related to the rescission of FASB Statements No. 4, 44 and 64, and for all transactions entered into after May 15, 2002 for the provision related to the amendments of FASB Statement No. 13. The Company does not believe there will be a material effect from the adoption of this standard on the Company's consolidated statements of financial position or results of operations.

Statement of Financial Accounting Standards No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"* ("SFAS 146"). In July 2002, the FASB issued SFAS 146. This statement requires that a liability for a cost associated with an exit or disposal activity be recognized at fair value when the liability is incurred and is effective for exit or disposal activities that are initiated after December 31, 2002 and nullifies EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." It also substantially nullifies EITF Issue No. 88-10, "Costs Associated with Lease Modification or Termination." Previously issued financial statements, including interim financial statements, cannot be restated. The Company does not expect its adoption of this standard in fiscal year 2003 to have a significant impact on its financial statements.

Statement of Financial Accounting Standards No. 148, *"Accounting for Stock-Based Compensation – Transition and Disclosure, Amendment of FASB Statement No. 123 and APB Opinion No. 28"* ("SFAS 148"). In December 2002, the FASB issued SFAS 148 that amended SFAS 123 to provide alternative methods of transition to SFAS 123's fair value method of accounting for stock-based employee compensation but does not require fair value accounting as prescribed in SFAS 123. SFAS 148 is effective for fiscal years ending after December 15, 2002. It also amends the disclosure provisions of SFAS 123 and Accounting Principles Board Opinion No. 28 to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. The disclosure provisions of SFAS 148 are incremental to the existing disclosure requirements of SFAS 123 and are applicable to all companies with stock-based compensation. The Company adopted the disclosure requirements of this standard in fiscal year 2002, but continues to account for stock-based compensation under APB 25.

Financial Accounting Standards Board ("FASB") Interpretation No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, an Interpretation of FASB Statements No. 5, 57, and 107 and rescission of FASB Interpretation No. 34"* ("FIN 45 "). In November 2002, the FASB issued FIN 45 which enhances the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees that it has issued. It also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligations it has undertaken in issuing the guarantee. FIN 45 applies to contracts or indemnification agreements that contingently require the guarantor to make payments to the guaranteed party based on changes in an underlying obligation that is related to an asset, liability, or an equity security of the guaranteed party. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The initial recognition and initial measurement provisions are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of initial application should not be revised or restated. The Company adopted FIN 45, and such adoption did not have a material impact on the financial statements.

Financial Accounting Standards Board ("FASB") Interpretation No. 46, *"Consolidation of Variable Interest Entities"*, an interpretation of Accounting Research Bulletin (ARB) No. 51, *"Consolidated Financial Statements" ("FIN 46")*. In January 2003, the FASB issued FIN 46 to address the consolidation of variable interest entities that have one or both of the following characteristics: (1) the equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, which is provided through other interests that will absorb some or all of the expected losses of the entity and (2) the equity investors lack one or more of the following essential characteristics of a controlling financial interest: (a) the direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights, (b) the obligation to absorb the expected losses of the entity if they occur, which makes it possible for the entity to finance its activities, or (c) the right to receive the expected residual returns of the entity if they occur, which is the compensation for the risk of absorbing the expected losses. FASB believes that if a business enterprise has a controlling financial interest in a variable interest entity, the assets, liabilities, and results of the activities of the variable interest entity should be included in consolidated financial statements with those of the business enterprise. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. There are also additional disclosure requirements for an enterprise that holds significant variable interests in a variable interest entity but is not the primary beneficiary. FIN 46 applies immediately to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date and may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. Currently, the Company does not have interests in any variable interest entity.

EITF 02-3 *"Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities"*, EITF 98-10 *"Accounting for Contracts Involved in Energy Trading and Risk Management Activities"* and Statement of Financial Accounting Standards No. 133 ("SFAS 133") *"Accounting for Derivative Instruments and Hedging Activities"*. On October 25, 2002, the EITF reached a final consensus on EITF 02-3 that rescinds EITF 98-10 and requires that all energy contracts held for trading purposes be presented on a net margin basis in the statement of earnings. The rescission of EITF 98-10 requires that energy contracts which do not meet the definition of a derivative under SFAS 133 no longer be marked-to-market and recognized in current earnings. As a result, all contracts which were marked to market under EITF 98-10 and must now be accounted for under the accrual method should be written back to cost with any difference included as a cumulative effect adjustment in the period of adoption. This transition provision will be effective for the first quarter of 2003. The rescission of EITF 98-10 did not have a material impact on the Company's financial condition or results of operations as all contracts previously marked-to-market under the definition provided in EITF 98-10 also met the definition of a derivative under SFAS 133 and are properly recorded at fair value with gains and losses recorded in earnings. The Company is reviewing its energy contract portfolio to determine whether its contracts meet the definition of trading activities under EITF 02-3 which should be presented on a net margin basis. The Company will reclassify prior periods to a net margin basis for those contracts previously accounted for under EITF 98-10 in the first quarter of 2003. The Company does not expect to report revenues and cost of energy sold on a net margin basis on a prospective basis as a result of the application of EITF 02-3 as none of the of Company's marketing activities meet the definitions of trading activities as prescribed by EITF 02-3.

QUARTERLY OPERATING RESULTS

The unaudited operating results by quarters for 2002 and 2001 are as follows:

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
2002:				
Operating Revenues	$ 313,996	$ 264,569	$ 289,440	$ 300,991
Operating Income	32,687	19,449	29,135	20,503
Net Earnings	24,949	11,157	17,797	10,369
Net Earnings per Share (Basic)	0.63	0.28	0.45	0.26
Net Earnings per Share (Diluted)	0.63	0.28	0.45	0.26
2001:				
Operating Revenues	$ 736,530	$ 666,091	$ 621,895	$ 315,301
Operating Income	77,300	80,547	47,422	17,408
Net Earnings	63,552	49,597	32,775	4,509
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

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)

COMPARATIVE OPERATING STATISTICS (UNAUDITED)

	2002	2001	2000	1999	1998
Utility Operations Sales:					
Energy Sales–KWh (in thousands):					
Residential	2,298,542	2,197,889	2,171,945	2,027,589	2,022,598
Commercial	3,254,576	3,213,208	3,133,996	2,981,656	2,909,752
Industrial	1,612,723	1,603,266	1,544,367	1,559,155	1,571,824
Other ultimate customers	240,665	240,934	238,635	235,183	235,700
Total KWh sales	7,406,506	7,255,297	7,088,943	6,803,583	6,739,874
Gas Throughput—Decatherms (in thousands):					
Residential	29,627	27,848	28,810	32,121	29,258
Commercial	12,009	10,421	9,859	11,106	10,044
Industrial	749	3,920	5,038	2,338	1,553
Other	4,806	4,355	6,426	6,538	8,390
Total gas sales	47,191	46,544	50,133	52,103	49,245
Transportation throughput	44,889	51,395	44,871	40,161	36,413
Total gas throughput	92,080	97,939	95,004	92,264	85,658
Utility Operations Revenues (in thousands):					
Electric Revenues:					
Residential	$ 197,174	$ 187,600	$ 186,133	$ 184,088	$ 187,681
Commercial	247,800	242,372	238,243	238,830	241,968
Industrial	82,009	82,752	79,671	85,828	88,644
Other ultimate customers	14,942	14,795	14,618	13,777	18,124
Total revenues to ultimate customers	541,925	527,519	518,665	522,523	536,417
Intersegment revenues	707	707	707	707	707
Miscellaneous electric revenues	28,164	31,707	20,093	18,345	19,151
Total electric revenues	$ 570,796	$ 559,933	$ 539,465	$ 541,575	$ 556,275
Gas Revenues:					
Residential	$ 172,200	$ 232,321	$ 191,231	$ 152,266	$ 160,398
Commercial	52,530	68,895	52,964	37,337	42,480
Industrial	2,872	27,519	24,206	8,550	4,887
Other	20,906	28,896	29,203	20,080	27,218
Revenues from gas sales	248,508	357,631	297,604	218,233	234,983
Transportation	17,735	20,188	14,163	12,390	13,464
Other	5,875	7,599	8,157	6,088	7,528
Total gas revenues	$ 272,118	$ 385,418	$ 319,924	$ 236,711	$ 255,975
Total Utility Revenues	$ 842,914	$ 945,351	$ 859,389	$ 778,286	$ 812,250

COMPARATIVE OPERATING STATISTICS (UNAUDITED)

	2002	2001	2000	1999	1998
Utility Customers at Year End:					
Electric:					
Residential	345,588	340,656	332,332	321,949	319,415
Commercial	41,092	40,065	39,525	38,435	37,652
Industrial	311	377	371	375	363
Other ultimate customers	796	924	625	625	665
Total ultimate customers	387,787	382,022	372,853	361,384	358,095
Sales for Resale	76	79	81	83	83
Total customers	387,863	382,101	372,934	361,467	358,178
Gas:					
Residential	411,642	404,753	398,623	390,428	383,292
Commercial	35,194	32,894	32,626	32,116	32,004
Industrial	58	50	50	51	55
Other	3,664	3,528	3,612	3,688	3,622
Transportation	27	34	32	32	29
Total customers	450,585	441,259	434,943	426,315	419,002
Generation and Marketing Operations Sales:					
Energy Sales—KWh (in thousands):					
Firm-requirements wholesale	581,428	616,703	330,003	179,249	278,615
Other contracted off-system	4,192,788	6,900,589	7,315,679	6,196,499	4,033,931
Economy energy sales	4,675,939	5,059,808	4,706,446	4,795,873	4,469,769
Total sales to ultimate customers	9,450,155	12,577,100	12,352,128	11,171,621	8,782,315
Intersegment sales	7,406,506	7,255,297	7,088,943	6,803,583	6,739,874
Total energy sales	16,856,661	19,832,397	19,441,071	17,975,204	15,522,189
Generation and Marketing Operations Revenues (in thousands):					
Firm-requirements wholesale	$ 25,973	$ 24,754	$ 15,540	$ 7,046	$ 10,708
Other contracted off-system	135,322	879,824	364,278	226,773	142,115
Economy energy sales	116,280	512,209	368,374	131,549	122,156
Total revenues to ultimate customers	277,575	1,416,787	748,192	365,368	274,979
Intersegment revenues	348,935	341,608	324,744	318,872	362,722
Miscellaneous electric revenues	47,810	(23,152)	2,242	5,741	4,657
Total generation revenues	$ 674,320	$ 1,735,243	$ 1,075,178	$ 689,981	$ 642,358
Generation and Marketing Operations Customers at Year End:	76	79	81	83	83

	2002	2001	2000	1999	1998
Reliable Net Capability—KW	1,734,000	1,521,000	1,521,000	1,521,000	1,506,000
Coincidental Peak Demand—KW	1,456,000	1,397,000	1,368,000	1,291,000	1,313,000
Average Fuel Cost per Million BTU	$ 1.3910	$ 1.6007	$ 1.3827	$ 1.3169	$ 1.2433
BTU per KWh of Net Generation	10,568	10,549	10,547	10,490	10,784

2003 ANNUAL MEETING

The 2003 Annual Meeting of Stockholders will be held at 9:30 am on May 13, 2003 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 4.

TRANSFER AGENT AND REGISTRAR

Corporate Headquarters:

Mellon Investor Services
PO Box 3338
South Hackensack 07606-1938
Phone: 1-877-663-7775
Website: melloninvestor.com

Overnight, Registered or Certified Mail:

Mellon Investor Services
85 Challenger Road
Ridgefield Park, NJ 07660

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

PNM Resources offers a dividend reinvestment and direct stock purchase plan as a service to both new investors and current shareholders. In addition to full or partial reinvestment of dividends, the PNM Direct Plan gives shareholders the opportunity to make direct cash investments. More information about the Plan and enrollment forms are available by calling Mellon Investor Services at 1-877-663-7775 or by visiting Mellon's website at melloninvestor.com.

SECURITIES INFORMATION

Exchange Listing and Stock Symbol

PNM Resources' common stock is listed on the New York Stock Exchange under the symbol PNM. The newspaper listing is PNM Res. As of December 31, 2002, there were 15,082 common shareholders of record.

Common Stock Prices* and Dividends Paid: (in dollars)

	2002					
Qtr.	Dividend	High	Low	Dividend	High	Low
1	$0.20	$30.760	$25.330	$0.20	$29.340	$22.875
2	$0.22	$30.550	$23.300	$0.20	$37.800	$28.700
3	$0.22	$24.330	$17.250	$0.20	$33.550	$24.752
4	$0.22	$24.670	$17.470	$0.20	$28.680	$24.350

**As reported by New York Stock Exchange Composite Price History*

REPORTS AND PUBLICATIONS

Copies of the Company's Form 10-K (annual report) and Form 10-Q (quarterly report) to the Securities and Exchange Commission (SEC), proxy statement, all news releases, an 11-year Financial and Statistical Report and other corporate literature are available free upon request by calling 505-241-2477, by accessing the information on the Internet at pnm.com or by writing the Vice President, Investor Relations.

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

CONTACT INFORMATION

Corporate Headquarters:

PNM Resources, Inc.
Alvarado Square
Albuquerque, NM 87158
Phone: 505-241-2700
Website: pnm.com

Investor Relations:

Barbara L. Barsky
Vice President, Investor Relations
Phone: 505-241-2662
Fax: 505-241-2367
E-Mail: bbarsky@pnm.com

OFFICERS OF PNM RESOURCES

JEFFRY E. STERBA, 47
Chairman, President and
Chief Executive Officer

ROGER J. FLYNN, 60
Executive VP, Chief Operating Officer

ALICE A. COBB, 55
Senior VP, People Services and Development

JOHN R. LOYACK, 39
Senior VP, Chief Financial Officer

MAX H. MAERKI, 63
Senior VP, Corporate Strategy and Development

PATRICK T. ORTIZ, 53
Senior VP, General Counsel and Secretary

EDDIE PADILLA, JR., 49
Senior VP, Power Marketing and Development

WILLIAM J. REAL, 54
Senior VP, Public Policy

BARBARA L. BARSKY, 58
VP, Investor Relations

ERNEST T. C'DE BACA, 49
VP, Governmental Affairs

TERRY R. HORN, 50
VP and Treasurer

ROBIN A. LUMNEY, 36
VP, Corporate Controller and Chief Accounting Officer

OFFICERS OF PNM (IN ADDITION TO LIST ABOVE)

MELVIN CHRISTOPHER, 42
VP, Operations and Engineering

PATRICK J. GOODMAN, 53
VP, Power Production

SARITA P. LOEHR, 45
VP, Customer Service

CINDY E. MCGILL, 46
VP, Regulatory Affairs

JOHN H. MYERS, 45
VP, Construction and Reliability

Effective as of March 1, 2003

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