MW Petroleum Corporation (A)

In late 1990, executives, engineers, and financial advisors working for Amoco Corporation and Apache Corporation began serious discussions about the sale to Apache of MW Petroleum Corporation, a wholly-owned subsidiary of Amoco Production Company. Amoco had transferred to MW certain of its own assets that it regarded as non-strategic. MW's size, location, and operations were all very attractive to Apache, which had grown nearly 30% per year since the mid-1980s, largely through acquisitions. The transaction being discussed with Amoco would be Apache's largest to date. It would more than double the size of Apache's current operations, as well as its reserves of oil and natural gas.

By the end of January 1991, Apache's executives and advisors were sufficiently familiar with the properties in MW to begin refining their estimates of operating and financial performance in order to structure a formal offer. Apache's chief financial officer, Mr. Wayne Murdy, knew that financing would be a challenge, given the size of the proposed transaction. In fact, the availability of external financing, bank debt in particular, was likely to impose some practical limits on both the amount and form of consideration that Apache could offer to Amoco. It was essential that Apache carefully evaluate MW, both the whole and its parts, and study the likely patterns of cash flows so that some creative financing alternatives could be developed.

Amoco Corporation

Amoco Corporation was an integrated petroleum and chemical company based in Chicago, Illinois. With $28 billion in operating revenues and $1.9 billion in net income in 1990, Amoco was the fifth largest oil company in the United States. Its three primary businesses were oil and gas exploration and production (Amoco Production Company), refining and marketing (Amoco Oil Company), and chemical production (Amoco Chemical Company). During the 1980s, Amoco had been an active acquiror of oil and gas properties, particularly the latter. Its 1988 purchase of Dome Petroleum of Canada made Amoco North America's largest private holder of natural gas reserves and the second largest producer of natural gas. In 1990, Amoco produced 3.5 billion cubic feet per day (BCFd) of natural gas and 782 thousand barrels per day (MBd) of crude oil and natural gas liquids.

Research Associate Barbara D. Wall prepared this case under the supervision of Professors Timothy A. Luehrman and Peter Tufano as the basis for class discussion rather than to illustrate either effective or ineffective handling of an administrative situation.

As of December 31, 1990, the company had estimated proved developed reserves totaling 5.1 billion barrels on an oil-equivalent basis.

The 1980s had been a difficult decade for the oil industry, Amoco included. [**Exhibit 1** summarizes historical financial data for Amoco during 1986-90.] From a high of over $37 per barrel in 1980, the price of oil on the spot market had fallen to just above $10/bbl in July 1986 and had recovered to only a little over $18/bbl by the end of the decade. Low prices depressed the profitability of oil companies, most of which responded with downsizing programs and other cost-cutting measures aimed at overhead expenses. Many major companies also sought to consolidate and rationalize their productive assets, which often meant divesting marginal properties. Since 1983, Amoco itself had sold more than $750 million worth of small properties which, it felt, could be more economically operated by smaller, low-overhead independent companies.

In 1988, Amoco conducted an extensive review of its cost structure and profitability. The study concluded that direct operating costs were well-controlled and offered little opportunity for major savings. However, it also showed that in the United States 85% of the company's gross margin was provided by just 11% of its 1150 producing fields and that many of the remaining fields had disproportionately high overhead and repair expenses. Based on these and other findings, Amoco initiated a major restructuring to better focus on its most attractive properties and opportunities. The first step was the sale, in 1989, of more than 400 fields in the "tail" of the margin curve, comprising approximately one third of the field portfolio and 12% of leases. These properties were among Amoco's least profitable, contributing only 3% of the company's direct margin.

Next, in January 1990, as part of the overall restructuring of Amoco Production Company, Amoco's board of directors approved a plan to divest up to $1.2 billion worth of additional properties from the middle section of the margin curve. Morgan Stanley was engaged to advise and assist in this process, which began with a review of different divestment alternatives. These included selling the properties in regional packages, spinning off a new public company, forming a joint venture, or retaining the properties until they were depleted but without making further material investment. Among these alternatives, a spin-off was judged most likely to produce the highest value for the properties. However, after further study it became clear that, for various reasons, a spin-off could take two or more years to accomplish, which reduced its attractiveness, not least because the future receptivity of the market was hard to forecast. Consequently, Amoco and Morgan Stanley decided to assemble the properties in a new, free-standing exploration and production entity called MW Petroleum Corporation. MW was to be a fully operational oil and gas company. In setting it up, Amoco faced myriad organizational, managerial, staffing, and other issues beyond the scope of this case. Ultimately, this turnkey operation was to be as large as many independent U.S. oil companies and could be marketed as such to non-U.S. bidders seeking to establish operations in the United States.

During the latter part of 1990, MW was shown to a number of targeted international petroleum concerns. For various reasons, all of these declined to bid. Toward the end of the year, U.S. buyers also were approached and Amoco considered offers from several different bidders. None of these offers was entirely satisfactory, however. One large independent oil company was interested in some, but not nearly all of MW; another oil and trading concern was interested in all of MW, but offered too low a price; and a venture capital group expressed interest, but Amoco doubted that it could obtain financing for its bid. The most promising expression of interest had come from Apache Corporation.

Apache Corporation

Apache Corporation was an independent oil and gas company based in Denver, Colorado and engaged in exploration, development, and production of oil and natural gas, primarily in the United States. It had earnings of $40 million in 1990 on revenues of $270 million and a market capitalization of $850 million. Apache's proven reserves totaled 106.1 million barrels on an oil-equivalent basis and were concentrated in the Gulf Coast region, in the Rocky Mountains, and in the Anadarko Basin of Oklahoma. Daily production in 1990 had been 259.1 million cubic feet (MMCF) of gas and 9.2 thousand barrels (MB) of oil. At these levels, on an oil-equivalent basis, Apache's gas production exceeded its oil production by about 4-to-1. Historical financial data for Apache are summarized in **Exhibit 2**.

Apache had low costs and was considered an efficient operator of small- to medium-sized properties. To exploit these strengths, Apache chairman Raymond Plank developed a strategy he labeled "rationalize and reconfigure." The strategy involved acquiring producing properties whose operations Apache could control and quickly make more efficient. In the 1980s, Apache's tactics frequently entailed significant borrowing to finance the purchase of a portfolio of properties, the best of which would be retained and operated, while the remainder was sold to help pay down debt. A total of more than $1.4 billion in assets were acquired in this fashion in the 1980s, with the two largest purchases each exceeding $400 million.

The properties in MW held several attractions for Apache. First, MW was a large company that would more than double Apache's reserves, and it was comprised mostly of properties well-suited to Apache's operating capabilities. Further, Amoco itself, on behalf of MW, operated fields accounting for nearly 80% of MW's production. This was considered a high operating percentage among U.S. producers and it promised Apache significant cost-saving opportunities (the remaining 20% of MW's production consisted of interests in fields operated by other companies). Adding MW to its portfolio also would shift Apache's oil-gas ratio from 20-80 to about 40-60. Such a shift was desirable because gas prices had been extremely volatile recently: during 1990 they had fallen nearly 50% from a four-year high at the beginning of the year. The resulting instability in Apache's revenue stream made high leverage more dangerous and the company's acquisition-driven growth strategy more difficult. Finally, MW's properties would further diversify Apache geographically. This would add further stability, enhance the company's standing among U.S. independents, and could lead to other future acquisition opportunities.

MW Petroleum Corporation

MW had been set up as a free-standing, wholly-owned subsidiary of Amoco, complete with its own reserves, management team, and with full ownership of or access to extensive geologic and engineering data from studies performed or purchased by Amoco on MW fields. MW's holdings included working interests in more than 9,500 wells in more than 300 producing fields situated on nearly 350,000 net acres in the Gulf Coast, Rocky Mountain, and Mid-continent regions and in the Permian Basin of Texas and New Mexico. The company's proved, probable, and possible reserves, as estimated by independent petroleum engineering consultants, totaled 264 million barrels on an oil-equivalent basis.[1] Of this, about 60% was oil and 40% gas. **Table A** gives a further breakdown of MW's reserves according to their engineering, development, and production status.

[1]To obtain a total for oil and gas reserves, 6 billion cubic feet (BCF) of gas are converted to one million barrels of oil-equivalent (MMBOE).

Table A: MW Petroleum's Estimated Reserves

	Oil (MMB)	Gas (MMCF)	Total (MMBOE)
Proved developed producing	73.6	381.1	137.1
Proved developed non-producing	7.9	61.5	18.1
Proved undeveloped	15.8	58.5	25.6
Total Proved	97.3	501.1	180.8
Total Probable	14.1	70.4	25.8
Total Possible	44.5	75.4	57.1
Total Reserves	155.9	646.9	263.7

Mr. Plank was interested in MW because most of its properties fit well with Apache's. Unfortunately, MW was simply too large for Apache to finance. As a result, Apache intended to exclude from its proposal a group of properties located in Michigan and the Gulf of Mexico that fit less well with its own portfolio. Amoco, for its part, indicated it would entertain such a proposal and, if it seemed promising, might even be willing to help locate financing.

Proved developed reserves MW had proved developed reserves associated with both producing and non-producing wells. They included projected production both from currently functioning wellbores and from others that required only modest expenditures to become fully operational. Apache was interested in 121.4 MMBOE of MW's proved developed reserves, or about 80% of the total. More than half of the reserves Apache proposed to exclude were gas. Annual production of oil and gas from the wells to be purchased would decline over time as the reserves were depleted. Though production could be slowed to extend the life of the reserves, this practice of "shutting in" reserves was rare in the United States. Oil production was expected to start at 9.4 MB in 1991 and decline to 1.2 MB in 2005. By that time, only 24% of the beginning proved developed crude oil reserves would remain in the ground. Similarly, gas production was expected to drop from 45.3 to 6.2 MMCF over the fifteen years from 1991 to 2005. At the end of 2005, only about 14% of the beginning gas reserves would remain. **Exhibit 3** presents projections for the production of proved developed reserves along with associated cash flows, excluding the above-mentioned fields in Michigan and the Gulf of Mexico.

Proved undeveloped reserves MW had other reserves that were proved but not developed. Developing these reserves would require drilling additional wells adjacent to existing wells, recompleting existing wellbores, or, in some cases, utilizing so-called "secondary" and "tertiary" recovery techniques. The most common of these was waterflooding, whereby a producing field is injected with water at selected sites to increase pressure in the field and push more oil and gas out of the ground. The properties in which Apache was interested comprised about 75% of MW's proved undeveloped reserves, including more than 80% of the available oil reserves. Bringing these reserves into production would require estimated expenditures for development of about $35 million over two years, and only minimal capital spending afterwards. Once these reserves were developed, about 70% of the oil and 90% of the gas could be extracted during the first fifteen years of production. In most fields, MW could leave these reserves undeveloped while retaining the right to develop them later. How long it could wait without forfeiting its rights varied from property to property, depending on the terms of the lease, on sharing arrangements with other companies, and on the level of production from other wells on the property. In virtually all cases, MW could wait 5-7 years without jeopardizing its rights. **Exhibit 4** shows production and cash flow projections for exploiting proved undeveloped reserves, excluding, once again, those reserves in Michigan and the Gulf of Mexico.

Probable reserves Geologic and engineering data showed some reserves to be potentially recoverable, but a lack of complete data or some unresolved uncertainty caused them to be classified as probable rather than proved reserves. Hence, production and cash flow forecasts for probable reserves often had to be "risk-weighted" based on available data and historical experience in comparable fields, to arrive at an estimate that reflected their expected value. Amounts actually recovered could be higher or lower, depending on geology and on the nature and extent of recovery operations undertaken. For the properties in MW, Amoco and Apache each made their own independent estimates. **Exhibit 5** presents production and cash flow projections for MW's probable reserves, excluding Michigan and the Gulf of Mexico. Exploiting probable reserves would require significant expenditures, exceeding $40 million in the first five years, for additional engineering to prove the reserves and then for subsequent development and production, mostly using secondary recovery techniques. As with undeveloped reserves, engineering and development expenditures could be deferred, at MW's option, for at least 5-7 years.

Possible reserves Possible reserves were speculative in that geologic and engineering data suggested the presence of significant amounts of oil or gas, but proving, developing, and recovering them was deemed fairly risky. Accordingly, these also had to be risk-weighted in order to arrive at production and operating forecasts. **Exhibit 6** shows that expenditures estimated at more than $100 million within the first five years would be necessary to recover these reserves should MW decide to pursue them. Anticipated expenditures were high because advanced recovery techniques, both secondary and tertiary, would be required to develop and produce possible reserves.

Other opportunities In addition to the existing reserves, there were other opportunities to create value from the properties in MW. Perhaps the most obvious, if not the easiest, was further exploration. Through MW, Apache would own or have access to sophisticated technical data gathered by Amoco. These data and further exploration of MW acreage might lead to the discovery of new reserves. All parties agreed, however, that the possibility of a major new discovery in these geographic areas was remote and the value of the exploration opportunities was probably about $25 million. This figure was not expected to be a controversial part of the negotiations.

The remaining opportunities did not involve increasing reserves, but finding ways to optimize production. Processes such as recompletion, plugback, well-deepening, and repair could be used on some existing wells to lower costs, extend well life, or increase the rate of production. Likewise, skillful timing and application of secondary and tertiary recovery methods could improve production even for wells in good repair. Such opportunities had to be recognized and exploited by the operator in field as they arose. Their net cash flow effects were positive, but usually not large for any one well, and difficult to estimate. They are not included in the projections shown in **Exhibits 3-6**. More generally, Apache believed it would be possible to lower the costs, both direct and indirect, of operating the properties in MW.

Aggregate MW cash flows The production and cash flow estimates presented in **Exhibits 3-6** for each of the different types of reserves are aggregated by year in **Exhibit 7** to produce one possible picture of the whole company, under specific purchase price, energy price, investment, and operating assumptions. In particular, **Exhibits 3-7** all exclude properties in Michigan and the Gulf of Mexico. Were these properties to be included at the time Apache bought MW, they almost certainly would be sold as soon as possible. Projected revenues were based on forecasts of oil and gas prices, which in turn were based on opinions offered by Morgan Stanley's economists (Amoco and Apache each also prepared private forecasts, for use internally). In late 1990, most forecasters predicted gradually rising prices for both oil and gas over the next fifteen years; they differed mainly in what they expected in the near term, during the Persian Gulf crisis, and in their specific predictions for the long-term rate of price increase.

Estimates of operating expenses and overhead in **Exhibits 3-7** also were developed by independent engineers and by Amoco and Morgan Stanley, respectively, not Apache. They were based, in the first instance, on historical costs, and in the second, on cash overhead savings Amoco actually expected to realize if MW were sold. Apache's experience could be better or worse, depending on how efficiently the properties were operated. Depreciation, depletion, and amortization estimates were compiled by the casewriter, based on schedules produced by Amoco and Morgan Stanley for the MW offering memorandum. These depended on the total purchase price, the allocation of the purchase price over the different reserves, and on the nature and timing of capital expenditures. Finally, **Exhibit 7** assumes that all opportunities are exploited without delay; that is, capital spending for proved undeveloped, probable, and possible reserves commences in 1991 and proceeds subsequently as shown in **Exhibits 3-6**. If some or all of these expenditures were postponed, the corresponding operating cash flows also would be delayed.

Risks

Oil and gas exploration and production in the United States had been a volatile business during the preceding twenty years. The prime cause was volatility in energy prices, which had been pronounced since the early 1970s. Oil prices in particular had long been influenced by global political and economic events in addition to local supply and demand conditions. The sharp drop in oil prices in 1986 was followed by a period of volatile, though generally rising prices, punctuated by an upward spike associated with the invasion of Kuwait by Iraq in August 1990. By January 1991, war had broken out in the Persian Gulf region. However, other oil-producing countries, principally Saudi Arabia, had increased production to offset disruptions in supply and most of the world was united in opposition to Iraq's occupation of Kuwait. As a result, by year-end 1990 oil prices had actually fallen from their September highs. Nevertheless, prices were volatile in early 1991 and many analysts expected them to remain so. The annualized standard deviation of oil price changes, calculated based on observed weekly price fluctuations, was just over 50% per year at the end of January 1991. During 1989 and the first half of 1990, this annualized standard deviation was usually between 20% and 30%, but it had risen steadily since the beginning of the Persian Gulf crisis. **Exhibit 8** displays historical data on oil prices and the standard deviation of oil price changes estimated from historical data on weekly prices.

Gas prices had declined gradually from their relatively high levels in 1984, but had become much more volatile as they were decontrolled. During most of 1988 and 1989, the standard deviation of changes in gas prices was lower than for oil price changes. Then, in the fall of 1989, the volatility of gas price changes jumped upward to an annualized standard deviation of about 40% per year, nearly twice as high as for oil price changes. Not until the fall of 1990 did oil once again become more volatile than gas. **Exhibit 8** displays data on historical gas prices and the standard deviation of gas price changes.

In addition to price volatility, Apache naturally would face uncertainties about the quantities of oil and gas to be produced from the MW fields and the expense of producing it. Some risks derived from unanswered geological and engineering questions regarding the amounts of oil and gas physically present and the likely success of secondary and tertiary recovery operations. MW's reserves had been quantified by Amoco and Amoco's external engineering consultants based on seismic and other geological data, Amoco's production experience to date, and other factors that determined the effectiveness of specific recovery techniques. Apache's engineers and advisors also were evaluating reserves and production operations. In addition to checking the independent reserve estimates, they were looking for cost-saving opportunities. The ability to manage costs—both direct costs and overhead—would be an important determinant of MW's profitability.

Structuring a Proposal

To take advantage of what they regarded as an attractive opportunity for growth, Apache's executives and advisors had to design a transaction that would satisfy Amoco's desire to sell MW at a good price; that would be profitable for Apache; and that could be financed externally with a large component of debt. This last requirement was expected to be especially difficult, given the large size of MW, the Ba3 rating of Apache's debt, and the current lending environment.

In 1991, the maximum loan-to-value ratio permitted by banks lending against oil and gas assets was typically 50% of the value of proved reserves. In addition, the credit approval process would require the analysis of a worst-case scenario, and loan terms would be set to protect the lender as much as possible in the worst case. The lending environment in 1991 was even tighter than these restrictions suggested, however, because U.S. banks were under pressure from regulators to improve the quality of their loan portfolios following losses on some highly levered transactions of the 1980s. Highly levered transactions were clearly out of favor, and some institutions were out of the market altogether, after the posting of reserves against bad loans had reduced their lending capacity. Consequently, there was a limited number of institutions among which to syndicate a large loan.

There were several possible ways to make an MW acquisition more attractive to lenders. One was to reduce its size, though both Amoco and Apache would oppose reducing it beyond a certain point. Another was to have Apache or MW issue equity either to Amoco, to the public, or to some other private investor. Both Amoco's and Apache's shares were traded on the New York Stock Exchange; historical stock price data for both companies is presented in **Exhibit 9**. Yet another possibility was for Amoco itself to lend to Apache, or to guarantee some part of Apache's external acquisition debt. Finally, Apache could expect to borrow more, the more it could reduce the banks' exposure to a worst-case scenario. Experienced lenders' prime concern was an unexpected drop in oil prices like the one that had occurred in 1986. In early 1991, with a war underway in the Persian Gulf, most experts foresaw higher rather than lower energy prices, though they varied a great deal in their prediction of the near-term path of prices. Not surprisingly though, banks were among the most conservative forecasters. Some had lent too aggressively following the oil price shocks of the 1970s, only to lose badly when oil prices fell.

Despite the problems Apache had to overcome, in at least one respect the lending environment was favorable. Inflation in the United States had been low for nearly a decade and interest rates had been generally falling. Long-term treasury bonds offered yields of 8% to 8.25%, and yields on B-rated debt had dropped more than 150 basis points in two months, despite the turmoil in the Middle East. Lower rates made whatever financing was available less expensive, and a lower opportunity cost of capital made long-term investments like MW more attractive. Contemporary financial market data are presented in **Exhibit 10**.

Exhibit 1 Amoco Corporation, Selected Historical Financial Data (in $ millions except as noted)

	1986	1987	1988	1989	1990
Income Statements					
Operating revenues	$18,281	$20,174	$21,150	$23,966	$28,010
Consumer excise taxes and other	2,064	2,282	2,769	2,794	3,571
Total revenues	20,345	22,456	23,919	26,760	31,581
Purchased crude oil, petroleum products & merchandise	7,593	8,970	8,471	10,619	13,697
Operating expenses	3,451	3,370	3,915	4,380	5,395
Petroleum exploration expenses	925	647	767	726	693
Selling and administrative expenses	1,358	1,424	1,466	1,888	1,991
Taxes other than income taxes	2,592	2,840	3,207	3,224	3,395
Depreciation, depletion and amortization	2,418	2,295	2,318	2,500	2,413
Interest expense	468	410	468	728	587
Total costs and expenses	18,805	19,956	20,612	24,065	28,171
Income before income taxes	1,540	2,500	3,307	2,695	3,410
Income taxes	793	1,140	1,244	1,085	1,497
Net income	747	1,360	2,063	1,610	1,913
Balance Sheets					
Current assets	4,200	5,899	5,393	6,428	8,216
Investments and other	1,337	1,072	1,431	1,355	1,287
Properties, net	18,169	18,151	23,095	22,647	22,706
Total assets	23,706	25,122	29,919	30,430	32,209
Current liabilities	4,180	4,503	4,799	5,148	6,092
Short term debt	174	468	444	483	492
Long term debt	3,556	3,303	6,274	5,915	5,464
Other liabilities	4,472	4,741	5,060	5,200	6,093
Shareholders' equity	11,324	12,107	13,342	13,684	14,068
Financial Ratios					
Return on operating revenues	4.1%	6.7%	9.8%	6.7%	6.8%
Return on assets	3.2%	5.4%	6.9%	5.3%	5.9%
Return on average equity	6.5%	11.6%	16.2%	11.9%	13.8%
Current ratio	0.9	1.1	1.0	1.1	1.2
Debt / capital ratio	19.1%	22.1%	32.4%	30.8%	28.8%
Interest coverage ratio	7.4	8.3	8.8	5.3	7.4
Debt rating	Aaa	Aaa	Aaa	Aaa	Aaa
Price - earnings ratio	22.59	14.7	10.0	14.4	15.4
Cash flow per share	$6.3	$7.1	$8.1	$8.0	$8.3
Common shares outstanding, (millions)	502.0	515.3	517.1	511.5	502.0
Year-end stock price	$32 3/4	$34 1/2	$37 1/2	$54 5/8	$52 3/8

Exhibit 2 Apache Corporation, Selected Historical Financial Data (in $ millions, except as noted)

	1986	1987	1988	1989	1990
Income Statements					
Revenues	106.0	100.5	141.7	246.9	273.4
Operating Expenses:					
Depreciation, depletion and amortization	82.1	184.6	61.4	96.3	116.8
Operating costs	23.5	25.5	27.6	42.5	44.6
Gathering and marketing costs			14.4	31.3	22.1
Administrative, selling and other	14.6	18.9	16.7	23.4	21.5
Financing costs, net	15.9	15.1	14.5	21.4	11.0
Income from continuing operations before income taxes	(30.1)	(143.6)	7.1	32.0	57.4
Provision for income taxes	(14.8)	(62.1)	1.6	9.8	17.2
Income from continuing operations	(15.3)	(81.5)	5.5	22.2	40.2
Discontinued operations:					
Income from discontinued operations, net of income taxes	4.4	0.6	2.6	0.0	0.0
Gain on sale of discontinued operations, net of income taxes	0.0	8.8	0.0	0.0	0.0
Net income before extraordinary item	(10.9)	(72.1)	8.1	22.2	40.2
Extraordinary item:					
Gain on early extinguishment from debt, net of income taxes	0.0	1.1	1.0	0.0	0.0
Net income (loss)	(10.9)	(71.0)	9.1	22.2	40.2
Balance Sheets					
Current assets	89.6	121.0	109.2	132.6	138.5
Property and equipment, net	490.7	363.4	570.9	603.6	663.4
Other assets	64.3	20.0	21.6	28.2	27.8
Total assets	644.6	504.4	701.7	764.4	829.7
Current liabilities	75.6	91.3	87.3	105.5	117.6
Long term debt	260.9	238.8	320.0	198.1	200.0
Shareholders' equity	207.4	128.8	206.9	350.3	386.8
Financial Ratios					
Return on assets			1.3%	2.9%	4.8%
Return on average equity			5.4%	8.0%	10.9%
Current ratio	1.17	1.26	1.11	1.23	1.13
Debt / capital ratio	55.7%	65.0%	60.7%	36.1%	34.1%
Interest expense (net)	15.9	15.1	14.5	21.4	11.0
Interest coverage			1.7	2.5	6.2
Debt rating (subordinated convertible debentures)	Ba3	B2	B2	NR[a]	Ba3
Price - earnings ratio			33.2	19.4	17.9
Cash flow per share	$2.87	$2.45	$2.03	$2.70	$3.52
Common shares outstanding (millions)	20.3	20.1	33.0	44.0	44.7
Year-end stock price	$9	$7 1//2	$7 7/8	$18 3/8	$14 5/8
Unlevered (asset) beta[b]					0.82

[a]Not rated.

[b]The mean asset beta, estimated by Morgan Stanley for six independent companies including Apache, was 0.64.

Exhibit 3 Proved Developed Reserves: Production and Cash Flow Projections ($ millions except as noted)

	Proved Developed Reserves	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
	Production:															
(1)	Crude and condensates (MB)	9.4	8.1	7.1	6.3	5.3	4.5	3.7	2.9	2.4	2.2	1.9	1.7	1.5	1.4	1.2
(2)	Gas (MMCF)	45.3	36.8	29.5	25.0	21.7	18.6	16.5	14.9	12.8	11.3	10.3	8.5	7.5	6.7	6.2
	Cash Flows (in millions):															
(3)	Revenues - oil	192.0	180.4	168.2	154.5	139.4	124.5	109.1	94.7	82.7	75.7	72.0	66.7	63.4	59.9	56.6
(4)	Revenues - gas	90.5	82.1	73.5	67.8	64.1	59.2	56.7	54.2	50.4	47.6	45.8	41.1	38.2	36.9	36.1
(5)	Total revenues	282.5	262.5	241.7	222.3	203.5	183.7	165.8	148.9	133.1	123.3	117.8	107.7	101.6	96.8	92.7
(6)	Direct production taxes	25.5	23.3	21.6	19.9	18.0	16.2	14.4	12.7	11.4	10.5	9.8	9.1	8.5	8.1	7.7
(7)	Direct operating expense	79.9	80.3	79.8	78.9	76.0	71.0	63.8	56.1	49.9	48.2	45.5	44.1	44.5	43.7	43.0
(8)	Overhead	33.9	32.2	28.6	25.9	23.0	20.4	18.3	16.1	13.9	12.6	10.8	9.7	9.0	8.3	7.8
(9)	Fin. book DD&A	58.0	45.2	35.6	29.1	23.8	19.1	19.6	16.6	13.3	10.7	9.0	7.5	6.3	5.3	4.5
(10)	Net income before taxes	85.2	81.2	76.1	68.6	62.7	57.0	49.7	47.4	44.6	41.4	42.8	37.3	33.3	31.3	29.7
(11)	Federal and state income taxes:															
(12)	Current	48.5	44.4	39.3	34.1	29.9	25.9	23.6	21.5	19.3	17.5	17.4	15.2	13.4	12.7	12.0
(13)	Deferred	(19.1)	(15.2)	(11.8)	(9.5)	(7.7)	(5.9)	(6.2)	(5.1)	(3.9)	(3.1)	(2.5)	(2.2)	(1.8)	(1.4)	(1.2)
(14)	Total income taxes	29.4	29.2	27.4	24.6	22.3	20.0	17.4	16.4	15.4	14.4	14.9	13.0	11.7	11.3	10.8
(15)	Profit contribution	55.8	52.0	48.6	43.9	40.4	37.0	32.2	31.0	29.2	27.0	27.9	24.3	21.7	20.0	18.9
(16)	Non-cash charges	38.9	30.1	23.7	19.6	16.1	13.2	13.5	11.5	9.5	7.7	6.4	5.3	4.5	4.0	3.3
(17)	Cash from operations	94.7	82.0	72.3	63.5	56.5	50.3	45.7	42.5	38.7	34.6	34.4	29.6	26.2	24.0	22.2
(18)	Capital expenditures	5.4	2.0	2.7	0.5	0.6	0.8	0.8	0.6	1.1	0.4	0.1	0.1	0.1	0.5	0.1
(19)	Cash flow	89.4	80.0	69.6	63.0	56.0	49.5	44.9	41.9	37.6	34.3	34.2	29.5	26.1	23.5	22.1
(20)	Terminal value															92.1
(21)	Cumulative cash flow	89.4	169.4	239.1	302.1	358.0	407.5	452.4	494.3	531.9	566.2	600.4	629.9	656.0	679.4	793.6

Notes to follow Exhibit 7.

Exhibit 4 Proved Undeveloped Reserves: Production and Cash Flow Projections ($ millions except as noted)

	Proved Undeveloped Reserves	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Production:															
(1)	Crude and condensates (MB)	0.3	0.6	0.5	0.5	0.5	0.5	0.5	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.6
(2)	Gas (MMCF)	1.7	4.9	5.6	3.3	2.3	2.0	2.0	2.2	2.3	1.9	1.6	1.3	1.3	1.0	0.9
	Cash Flows (in millions):															
(3)	Revenues - oil	6.0	14.0	12.9	11.8	12.3	13.2	16.1	21.0	27.1	25.2	25.3	26.8	28.7	30.9	29.3
(4)	Revenues - gas	3.4	11.3	14.5	9.1	6.7	6.2	6.6	7.1	8.2	7.2	6.6	5.5	5.2	5.2	4.5
(5)	Total revenues	9.4	25.3	27.4	20.9	19.0	19.4	22.7	28.1	35.3	32.4	31.9	32.3	33.9	36.1	33.8
(6)	Direct production taxes	0.9	2.4	2.3	1.8	1.7	1.7	2.0	2.5	3.1	2.8	2.8	3.0	3.1	2.9	3.0
(7)	Direct operating expense	1.2	1.5	2.0	2.3	2.8	3.4	3.3	3.3	4.5	3.4	3.7	4.2	4.5	4.7	4.8
(8)	Overhead	1.1	3.1	3.2	2.4	2.1	2.2	2.5	3.0	3.7	3.3	2.9	2.9	3.0	3.1	2.8
(9)	Fin. book DD&A	12.3	12.6	10.6	9.3	8.1	6.7	6.8	5.8	4.6	3.7	4.3	3.6	3.0	2.5	2.1
(10)	Net income before taxes	(6.2)	5.7	9.2	5.1	4.2	5.5	8.1	13.5	19.5	19.2	18.2	18.6	20.3	22.8	21.1
(11)	Federal and state income taxes:															
(12)	Current	2.1	6.4	7.0	5.0	4.3	4.1	5.1	6.5	8.0	7.7	7.6	7.5	7.9	8.8	8.1
(13)	Deferred	(4.1)	(4.2)	(3.5)	(3.0)	(2.6)	(2.1)	(2.1)	(1.8)	(1.3)	(1.1)	(1.2)	(1.0)	(0.9)	(0.7)	(0.6)
(14)	Total income taxes	(2.0)	2.2	3.5	2.0	1.7	2.1	2.9	4.7	6.7	6.6	6.3	6.5	7.1	8.1	7.5
(15)	Profit contribution	(4.2)	3.5	5.8	3.1	2.5	3.4	5.1	8.8	12.8	12.6	11.8	12.1	13.3	14.7	13.5
(16)	Non-cash charges	8.3	8.4	7.1	6.3	5.5	4.6	4.7	4.0	3.2	2.6	3.1	2.5	2.2	1.9	1.6
(17)	Cash from operations	4.0	11.9	12.9	9.3	8.1	8.0	9.8	12.8	16.0	15.2	14.9	14.7	15.4	16.6	15.1
(18)	Capital expenditures	17.5	17.7	5.3	4.1	3.5	1.3	0.1	0.3	0.0	0.1	8.1	(0.0)	0.2	0.0	(0.0)
(19)	Cash flow	(13.5)	(5.8)	7.6	5.2	4.6	6.7	9.7	12.5	16.0	15.1	6.8	14.7	15.2	16.5	15.1
(20)	Terminal value															67.8
(21)	Cumulative cash flow	(13.5)	(19.3)	(11.7)	(6.4)	(1.9)	4.9	14.6	27.1	43.1	58.2	65.0	79.7	95.0	111.5	194.3

Notes follow Exhibit 7.

Exhibit 5 Probable Reserves: Production and Cash Flow Projections ($ millions except as noted)

	Probable Reserves	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Production:															
(1)	Crude and condensates (MB)	0.2	0.3	0.4	0.4	0.5	0.5	0.7	0.9	0.8	0.7	0.6	0.5	0.4	0.4	0.3
(2)	Gas (MMCF)	2.8	4.2	4.9	5.3	4.2	3.8	4.5	4.2	3.3	2.4	2.1	2.0	1.5	1.3	1.1
	Cash Flows (in millions):															
(3)	Revenues - oil	3.7	6.3	8.0	9.6	13.3	14.3	17.0	19.6	20.3	19.8	18.6	17.1	15.8	14.5	13.4
(4)	Revenues - gas	5.8	9.4	11.6	14.1	12.3	12.3	13.0	11.6	10.7	9.3	9.5	10.1	8.8	8.1	7.3
(5)	Total revenues	9.5	15.7	19.5	23.7	25.7	26.6	30.0	31.2	31.0	29.2	28.1	27.2	24.7	22.6	20.6
(6)	Direct production taxes	0.8	1.3	1.7	2.0	2.2	2.3	2.7	2.9	3.1	3.0	2.8	2.7	2.5	2.3	2.1
(7)	Direct operating expense	0.4	0.7	0.8	2.6	4.4	4.7	5.3	5.7	6.0	6.4	7.0	7.4	7.4	7.3	7.2
(8)	Overhead	1.3	1.9	2.3	2.8	3.0	2.9	3.1	3.3	3.0	2.8	2.6	2.5	2.2	2.0	1.9
(9)	Fin. book DD&A	0.4	0.8	1.2	2.5	1.5	1.3	1.5	2.0	1.5	1.4	1.4	1.4	1.4	1.3	1.3
(10)	Net income before taxes	6.6	11.0	13.5	13.8	14.5	15.4	17.3	17.4	17.5	15.5	14.3	13.3	11.3	9.6	8.1
(11)	Federal and state income taxes:															
(12)	Current	2.9	3.7	4.8	4.8	3.8	4.2	5.5	5.8	5.5	5.4	5.0	4.7	4.0	3.5	3.0
(13)	Deferred	(0.2)	(0.0)	(0.2)	(0.2)	0.3	0.3	0.1	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Total income taxes	2.6	3.7	4.6	4.5	4.1	4.5	5.6	5.7	5.6	5.4	5.0	4.7	4.0	3.5	3.0
(15)	Profit contribution	4.0	7.3	8.9	9.3	10.5	10.8	11.7	11.7	11.9	10.1	9.3	8.6	7.2	6.1	5.1
(16)	Non-cash charges	0.2	0.8	1.1	2.2	1.9	1.6	1.6	1.9	1.6	1.4	1.4	1.4	1.4	1.4	1.3
(17)	Cash from operations	4.2	8.1	9.9	11.5	12.3	12.4	13.4	13.6	13.5	11.5	10.7	10.0	8.6	7.5	6.4
(18)	Capital expenditures	10.0	4.3	11.4	14.0	2.6	0.5	0.3	0.6	0.3	0.5	0.5	0.0	0.2	0.5	0.0
(19)	Cash flow	(5.8)	3.8	(1.5)	(2.5)	9.7	11.9	13.1	13.0	13.2	11.0	10.2	10.0	8.4	7.0	6.4
(20)	Terminal value															51.0
(21)	Cumulative cash flow	(5.8)	(2.0)	(3.5)	(6.0)	3.7	15.7	28.8	41.8	55.0	66.0	76.3	86.3	94.7	101.7	159.0

Notes follow Exhibit 7.

Exhibit 6 Possible Reserves: Production and Cash Flow Projections ($ millions except as noted)

	Possible Reserves	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Production:															
(1)	Crude and condensates (MB)	0.1	3.8	0.9	0.8	0.8	1.0	1.6	2.1	2.4	2.3	2.0	1.7	1.6	1.4	1.2
(2)	Gas (MMCF)	0.5	3.5	3.8	3.3	3.6	3.7	3.2	3.0	3.2	2.8	1.9	1.3	1.4	1.2	1.0
	Cash Flows (in millions):															
(3)	Revenues - oil	2.1	10.1	13.2	14.4	18.0	24.1	42.3	59.1	67.4	69.4	66.8	62.7	59.7	56.4	52.0
(4)	Revenues - gas	0.6	3.6	5.1	6.9	7.2	7.7	7.7	7.0	7.8	9.3	8.1	5.1	5.9	5.9	5.7
(5)	Total revenues	2.7	13.7	18.3	21.3	25.1	31.8	50.0	66.1	75.2	78.7	74.9	68.8	65.7	62.3	57.7
(6)	Direct production taxes	0.3	1.2	1.6	1.8	2.2	2.8	5.0	6.8	7.9	8.0	7.1	6.7	6.4	6.1	5.6
(7)	Direct operating expense	0.2	1.0	1.5	2.1	6.5	13.1	21.2	31.9	33.0	35.1	26.4	26.3	25.7	25.8	25.6
(8)	Overhead	0.4	1.6	2.1	2.5	2.9	3.4	5.2	6.9	7.3	7.6	6.9	5.3	5.9	5.7	5.3
(9)	Fin. book DD&A	0.7	1.4	2.2	4.9	3.5	3.1	3.6	4.5	3.5	3.3	3.3	3.2	3.2	3.1	3.1
(10)	Net income before taxes	1.2	8.5	10.9	10.0	10.0	9.4	15.0	16.0	23.4	24.6	31.1	26.2	24.5	21.6	18.1
(11)	Federal and state income taxes:															
(12)	Current	0.8	3.1	4.2	4.4	3.2	3.2	5.4	6.1	7.8	8.9	10.9	9.4	8.8	7.9	6.7
(13)	Deferred	(0.4)	(0.0)	(0.3)	(0.5)	0.7	0.7	0.2	(0.2)	0.2	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Total income taxes	0.3	3.1	4.0	3.9	3.8	3.9	5.6	6.0	8.0	8.9	11.0	9.4	8.8	7.9	6.8
(15)	Profit contribution	0.8	5.4	7.0	6.2	6.1	5.5	9.3	10.0	15.4	15.7	20.2	16.9	15.7	13.7	11.4
(16)	Non-cash charges	0.3	1.4	1.9	4.4	4.2	3.8	3.6	4.4	3.7	3.3	3.3	3.3	3.2	3.2	3.1
(17)	Cash from operations	1.1	6.8	8.9	10.6	10.4	9.3	13.2	14.4	19.1	19.1	23.5	20.1	18.9	16.9	14.5
(18)	Capital expenditures	9.7	9.8	22.4	38.9	27.4	6.8	0.7	1.0	0.7	3.0	2.3	0.0	0.1	0.0	0.0
(19)	Cash flow	(8.6)	(2.9)	(13.5)	(28.4)	(17.1)	2.5	12.5	13.4	18.5	16.1	21.2	20.1	18.8	16.8	14.4
(20)	Terminal value															72.3
(21)	Cumulative cash flow	(8.6)	(11.6)	(25.1)	(53.5)	(70.6)	(68.1)	(55.6)	(42.2)	(23.8)	(7.7)	13.5	33.6	52.4	69.2	155.9

Notes follow Exhibit 7.

Exhibit 7 Aggregated MW Production and Cash Flow Projections ($ millions except as noted)

	Aggregated MW Projections	Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Production:															
(1)	Net crude and condensates (MB)	10.0	9.8	8.9	8.1	7.1	6.5	5.5	6.6	6.4	5.8	5.2	4.6	4.3	3.8	3.4
(2)	Net gas (MMCF)	50.2	49.5	43.7	37.5	31.8	28.1	26.2	24.4	21.6	18.3	15.9	13.1	11.8	10.2	9.3
	Cash Flows (in millions):															
(3)	Revenues - oil	203.9	210.9	202.3	190.3	183.0	176.1	184.5	194.4	197.5	190.2	182.7	173.2	167.7	161.7	151.3
(4)	Revenues - gas	100.3	106.3	104.7	97.9	90.3	85.4	84.0	80.0	77.2	73.4	70.0	62.8	58.1	56.1	53.5
(5)	Total revenues	304.1	317.2	306.9	288.3	273.3	261.5	268.5	274.4	274.7	263.6	252.7	236.0	225.8	217.8	204.8
(6)	Direct production taxes	27.5	28.5	27.3	25.5	24.1	23.0	24.1	25.0	25.4	24.3	22.5	21.5	20.4	19.4	18.4
(7)	Direct operating expense	81.7	83.5	84.1	85.9	89.7	92.2	93.7	97.0	93.3	93.2	82.6	82.0	82.0	81.5	80.6
(8)	Overhead	36.6	38.7	36.3	33.6	31.0	28.8	29.2	29.3	27.9	26.3	23.2	21.4	20.1	19.1	17.8
(9)	Fin. book DD&A	71.4	60.0	49.6	45.7	37.0	30.2	31.6	28.9	23.0	19.2	18.0	15.7	13.8	12.3	11.0
(10)	Net income before taxes	86.8	106.5	109.7	97.5	91.5	87.2	90.0	94.3	105.0	100.7	106.5	95.5	89.5	85.4	77.0
(11)	Federal and state income taxes:															
(12)	Current	54.2	57.6	55.3	48.3	41.2	37.4	39.5	39.9	40.7	39.4	40.9	36.8	34.2	32.8	29.8
(13)	Deferred	(23.8)	(19.4)	(15.8)	(13.2)	(9.3)	(7.0)	(7.9)	(7.1)	(4.9)	(4.1)	(3.7)	(3.2)	(2.6)	(2.0)	(1.8)
(14)	Total income taxes	30.4	38.2	39.5	35.0	31.9	30.5	31.6	32.8	35.8	35.3	37.2	33.6	31.6	30.8	28.1
(15)	Profit contribution	56.4	68.3	70.3	62.5	59.5	56.8	58.4	61.5	69.2	65.3	69.2	61.9	57.9	54.5	48.9
(16)	Non-cash charges	47.6	40.6	33.8	32.4	27.7	23.3	23.6	21.8	18.1	15.1	14.3	12.5	11.3	10.4	9.3
(17)	Cash from operations	104.0	108.9	104.0	95.0	87.3	80.0	82.1	83.3	87.3	80.4	83.5	74.4	59.1	64.9	58.2
(18)	Capital expenditures	42.6	33.8	41.8	57.5	34.1	9.4	1.9	2.6	2.0	3.9	11.0	0.0	0.5	1.1	0.2
(19)	Cash flow	61.4	75.1	62.2	37.4	53.2	70.7	80.2	80.7	85.3	76.5	72.5	74.3	68.5	63.8	58.0
(20)	Terminal value															283.1
(21)	Cumulative cash flow	61.4	136.5	198.8	236.2	289.3	360.0	440.2	520.9	606.2	682.7	755.2	829.5	898.0	961.8	1302.9

Notes follow Exhibit 7.

Line Notes to MW Petroleum Projections, Exhibits 3 - 7

(0) The cash flow projections presented in **Exhibits 3-7** were prepared by the casewriter based primarily on operating and financial data from the MW offering memorandum.

(1) Crude and condensates - annual production quantities of crude oil and associated liquid hydrocarbons expressed in thousands of barrels (MB). One barrel is equivalent to 42 gallons.

(2) Gas - annual production quantities of gas expressed in millions of standard cubic feet (MMCF). A standard cubic foot is one cubic foot of gas at one atmosphere and 60 degrees Fahrenheit.

(3-5) Revenues - projected annual oil, gas and total revenues, net of royalties, based upon the production quantities on lines 1 and 2.

(6) Direct production taxes - includes production and ad valorem taxes.

(7) Direct operating expense - includes lease and well operating costs, escalated at 5% per year.

(8) Overhead - general and administrative expenses, such as non-field personnel compensation, as estimated by Amoco and Morgan Stanley.

(9) Financial book DD&A - depreciation, depletion and amortization, computed for financial reporting purposes, including allocation and amortization of the purchase price; estimated by the casewriter, based on the MW offering memorandum.

(10) Net income before taxes - revenues less the sum of the expenses in lines 6 through 9.

(11) Federal and state income taxes - projected federal and state income tax expense broken down into current and deferred portions.

(12) Current - the current portion of federal and state income taxes.

(13) Deferred - the deferred portion of federal and state income taxes relating primarily to the timing difference in book versus tax treatment of DD&A.

(14) Total income taxes - the sum of current and deferred taxes on lines 12 and 13.

(15) Profit contribution - the difference between net income before taxes on line 10 and total income taxes on line 14.

(16) Non-cash charges - includes financial book DD&A and deferred income taxes.

(17) Cash from operations - profit contribution (line 15) plus non-cash charges (line 16).

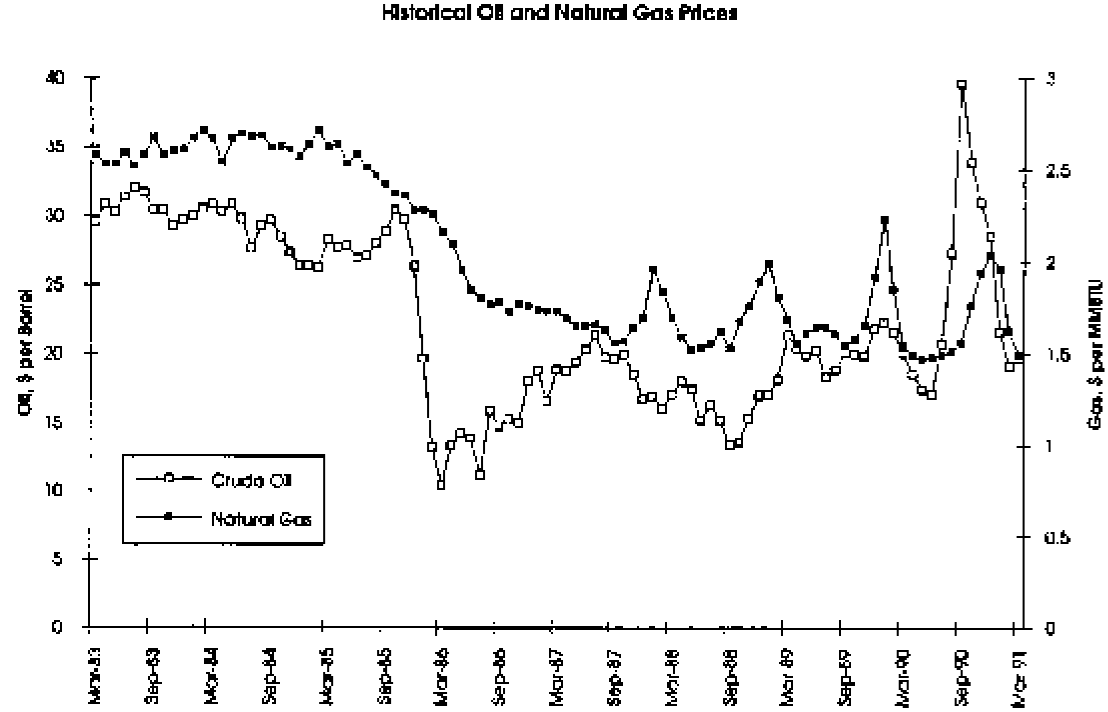
(18) Capital expenditures - investments (including additions to working capital) required to perform procedures and projects such as workovers, recompletions, development drilling, waterflooding, etc., to extract additional reserves.

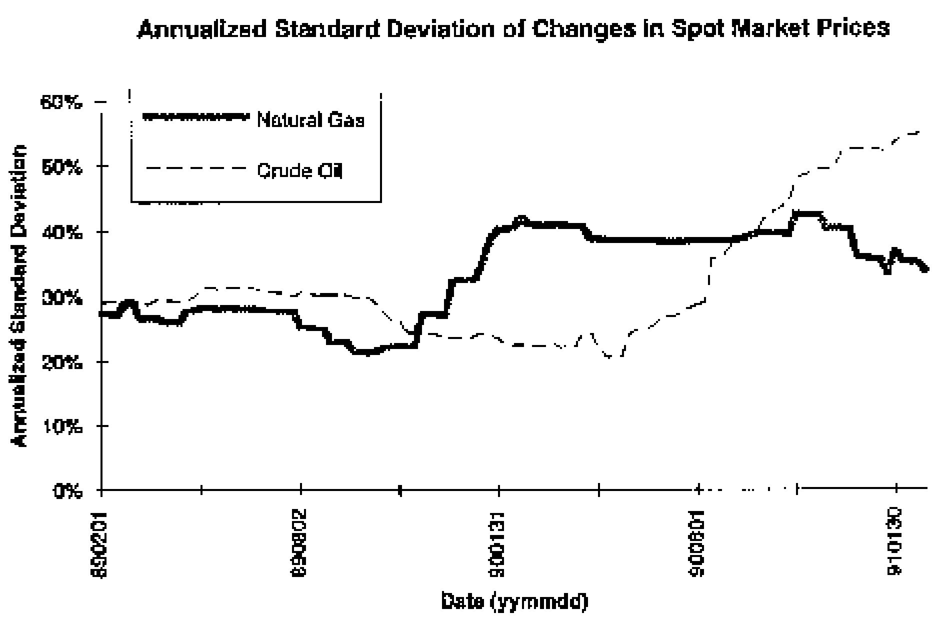
(19) Cash flow - cash from operations less capital expenditures.

(20) Terminal value - the estimated present value, in year 15, of all future net cash flows until reserves are exhausted. Discounting performed at 13% per year.

(21) Cumulative cash flow - the accumulated value of the cash flows presented in line 19.

Exhibit 8 Historical Oil and Natural Gas Prices and Volatilities





Note: Annualized standard deviation is estimated using 52 observations of historical weekly price changes.

Exhibit 9 Historical Stock Price Data for Amoco and Apache

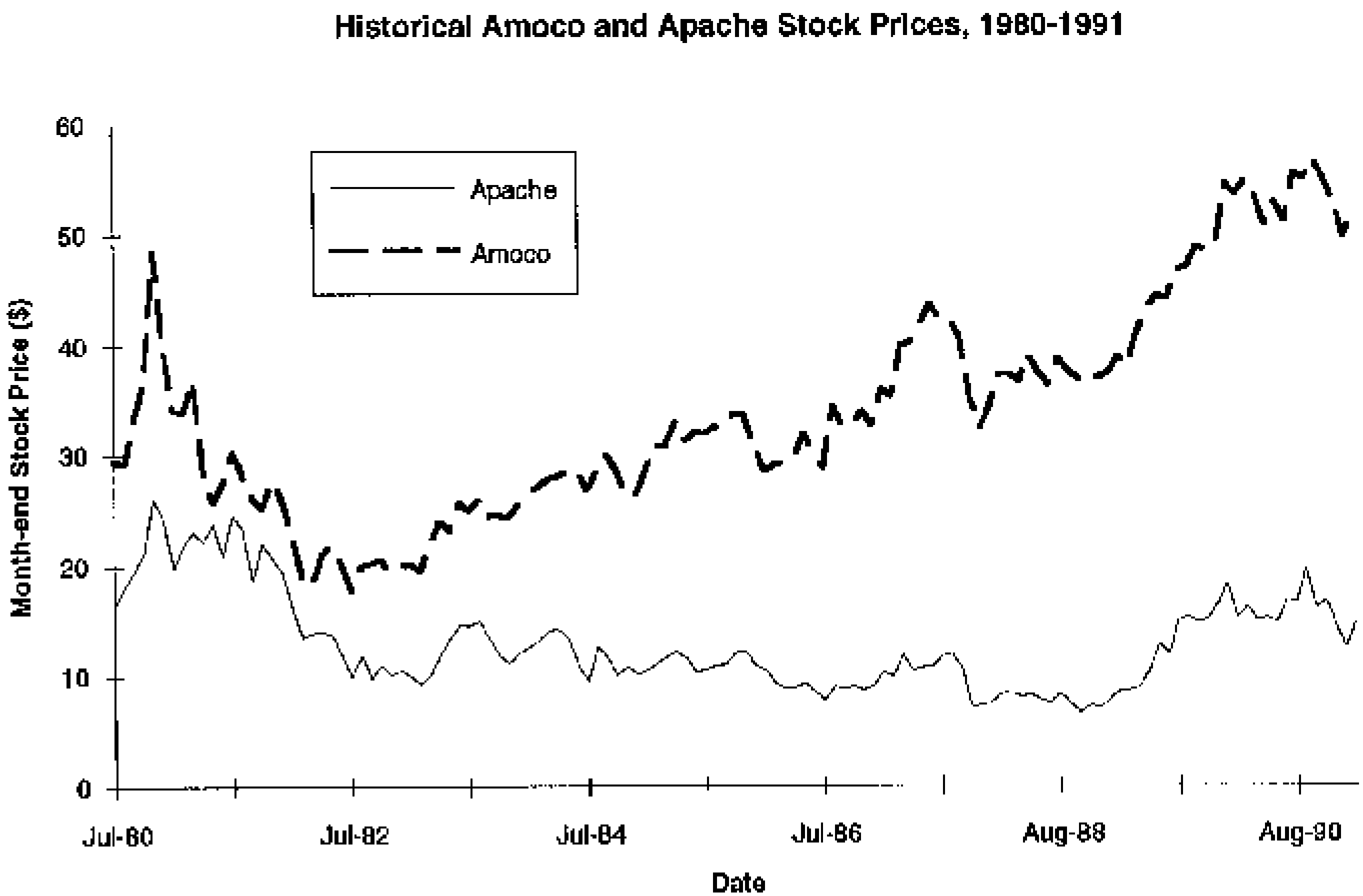


Exhibit 10 Selected Contemporary Financial Market Data

U.S. Government Bond Yields, Year-end 1990

Term	Yield
30-day	6.52%
10-year	8.03%
30-year	8.24%

Note: Yields are expressed on a bond-equivalent basis.

Industrial Bond Yields

Rating	Dec-90	Jan-91	Feb-91
AAA	9.08%	8.95%	8.80%
AA	9.45%	9.40%	9.09%
A	9.54%	9.50%	9.29%
BBB	11.55%	11.67%	10.38%
BB	12.41%	12.24%	12.30%
B	19.02%	20.20%	17.37%

Sources: *Wall Street Journal*, Morgan Stanley, *Standard & Poor's*.