HOLLY CORP
Form 10-Q
November 09, 2007

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2007

OR

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

For the transition period from __________ to __________

Commission File Number 1-3876

HOLLY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	75-1056913
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
100 Crescent Court, Suite 1600 Dallas, Texas	75201-6915
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code (214) 871-3555

Former name, former address and former fiscal year, if changed since last report

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act). (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

55,312,125 shares of Common Stock, par value $.01 per share, were outstanding on October 31, 2007.

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PART I. FINANCIAL INFORMATION

FORWARD-LOOKING STATEMENTS

References herein to Holly Corporation include Holly Corporation and its consolidated subsidiaries. In accordance with the Securities and Exchange Commission s (SEC) Plain English guidelines, this Quarterly Report on Form 10-Q has been written in the first person. In this document, the words we , our , ours and us refer only to Holly Corporatio and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

This Quarterly Report on Form 10-Q contains certain forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical fact included in this Form 10-Q, including, but not limited to, those under Results of Operations, Liquidity and Capital Resources and Risk Management in Item 2 Management s Discussion and Analysis of Financial Condition and Results of Operations in Part I and those in Item 1 Legal Proceedings in Part II, are forward-looking statements. These statements are based on management s beliefs and assumptions using currently available information and expectations as of the date hereof, are not guarantees of future performance and involve certain risks and uncertainties. Although we believe that the expectations reflected in these forward-looking statements are reasonable, we cannot assure you that our expectations will prove to be correct. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in these statements. Any differences could be caused by a number of factors, including, but not limited to:

- risks and uncertainties with respect to the actions of actual or potential competitive suppliers of refined petroleum products in our markets;
- the demand for and supply of crude oil and refined products;
- the spread between market prices for refined products and market prices for crude oil;
- the possibility of constraints on the transportation of refined products;
- the possibility of inefficiencies, curtailments or shutdowns in refinery operations or pipelines;
- effects of governmental regulations and policies;
- the availability and cost of our financing;
- the effectiveness of our capital investments and marketing strategies;
- our efficiency in carrying out construction projects;
- our ability to acquire refined product operations on acceptable terms and to integrate any future acquired operations;
- the possibility of terrorist attacks and the consequences of any such attacks;
- general economic conditions; and
- other financial, operational and legal risks and uncertainties detailed from time to time in our Securities and Exchange Commission filings.

Cautionary statements identifying important factors that could cause actual results to differ materially from our expectations are set forth in this Form 10-Q, including without limitation in conjunction with the forward-looking statements included in this Form 10-Q that are referred to above. This summary discussion should be read in conjunction with the discussion of risk factors and other cautionary statements under the heading Risk Factors included in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006 and in conjunction with the discussion in this Form 10-Q in Management s Discussion and Analysis of Financial Condition and Results of Operations under the headings Liquidity and Capital Resources. All forward-looking statements included in this Form 10-Q and all subsequent written or oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. The forward-looking statements speak only as of the date made and, other than as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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DEFINITIONS

Within this report, the following terms have these specific meanings:

Alkylation means the reaction of propylene or butylene (olefins) with isobutane to form an iso-paraffinic gasoline (inverse of cracking).

BPD means the number of barrels per calendar day of crude oil or petroleum products.

BPSD means the number of barrels per stream day (barrels of capacity in a 24 hour period) of crude oil or petroleum products.

Catalytic reforming means a refinery process which uses a precious metal (such as platinum) based catalyst to convert low octane naphtha to high octane gasoline blendstock and hydrogen. The hydrogen produced from the reforming process is used to desulfurize other refinery oils and is the main source of hydrogen for the refinery.

Cracking means the process of breaking down larger, heavier and more complex hydrocarbon molecules into simpler and lighter molecules.

Crude distillation means the process of distilling vapor from liquid crudes, usually by heating, and condensing slightly above atmospheric pressure the vapor back to liquid in order to purify, fractionate or form the desired products.

Ethanol means a high octane gasoline blend stock that is used to make various grades of gasoline.

FCC, or fluid catalytic cracking, means a refinery process that breaks down large complex hydrocarbon molecules into smaller more useful ones using a circulating bed of catalyst at relatively high temperatures.

Hydrocracker means a refinery unit that breaks down large complex hydrocarbon molecules into smaller more useful ones using a fixed bed of catalyst at high pressure and temperature with hydrogen.

Hydrodesulfurization means to remove sulfur and nitrogen compounds from oil or gas in the presence of hydrogen and a catalyst at relatively high temperatures.

Hydrogen plant means a refinery unit that converts natural gas and steam to high purity hydrogen, which is then used in the hydrodesulfurization, hydrocracking and isomerization processes.

HF alkylation, or hydrofluoric alkylation, means a refinery process which combines isobutane and C3/C4 olefins using HF acid as a catalyst to make high octane gasoline blend stock.

Isomerization means a refinery process for rearranging the structure of C5/C6 molecules without changing their size or chemical composition and is used to improve the octane of C5/C6 gasoline blendstocks.

LPG means liquid petroleum gases.

LSG, or low sulfur gasoline, means gasoline that contains less than 30 PPM of total sulfur.

MMBtu or one million British thermal units, means for each unit, the amount of heat required to raise one pound of water one degree Fahrenheit at one atmosphere pressure.

MMSCFD means one million standard cubic feet per day.

MTBE means methyl tertiary butyl ether, a high octane gasoline blend stock that is used to make various grades of gasoline.

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Natural gasoline means a low octane gasoline blend stock that is purchased and used to blend with other high octane stocks produced to make various grades of gasoline.

PPM means parts-per-million.

Refinery gross margin means the difference between average net sales price and average costs of products per barrel of produced refined products. This does not include the associated depreciation, depletion and amortization costs.

Reforming means the process of converting gasoline type molecules into aromatic, higher octane gasoline blend stocks while producing hydrogen in the process.

ROSE , or Solvent deasphalter / residuum oil supercritical extraction, means a refinery unit that uses a light hydrocarbon like propane or butane to extract non asphaltene heavy oils from asphalt or atmospheric reduced crude. These deasphalted oils are then further converted to gasoline and diesel in the FCC process. The remaining asphaltenes are either sold, blended to fuel oil or blended with other asphalt as a hardener.

Sour crude oil means crude oil containing quantities of sulfur greater than 0.4 percent by weight, while sweet crude oil means crude oil containing quantities of sulfur equal to or less than 0.4 percent by weight.

ULSD, or ultra low sulfur diesel, means diesel fuel that contains less than 15 PPM of total sulfur.

Vacuum distillation means the process of distilling vapor from liquid crudes, usually by heating, and condensing below atmospheric pressure the vapor back to liquid in order to purify, fractionate or form the desired products.

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Item 1. Financial Statements

HOLLY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	September 30, 2007 (Unaudited)	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 39,034	$ 154,117
Marketable securities	184,782	96,168
Accounts receivable: Product and transportation	222,233	199,083
Crude oil resales	359,704	196,842
Related party receivable	1,481	2,198
	583,418	398,123
Inventories: Crude oil and refined products	165,106	115,100
Materials and supplies	14,698	14,575
	179,804	129,675
Income taxes receivable	12,306	9,055
Prepayments and other	12,954	12,081
Assets of discontinued operations		355
Total current assets	1,012,298	799,574
Properties, plants and equipment, at cost	755,042	642,740
Less accumulated depreciation, depletion and amortization	(263,139)	(237,270)
	491,903	405,470
Marketable securities (long-term)	85,914	5,668
Other assets: Turnaround costs	8,467	12,061
Intangibles and other	13,131	15,096
	21,598	27,157
Total assets	$ 1,611,713	$ 1,237,869

LIABILITIES AND STOCKHOLDERS EQUITY

Current liabilities:

Accounts payable	$ 681,648	$ 507,566
Accrued liabilities	51,452	51,173
Liabilities of discontinued operations		654
Total current liabilities	733,100	559,393
Deferred income taxes	31,275	20,776
Other long-term liabilities	14,857	27,201
Commitments and contingencies		
Distributions in excess of investment in Holly Energy Partners	167,406	164,405
Stockholders equity:		
Preferred stock, $1.00 par value 1,000,000 shares authorized; none issued		
Common stock $.01 par value 160,000,000 and 100,000,000 shares authorized; 72,375,069 and 71,825,960 shares issued as of September 30, 2007 and December 31, 2006, respectively	724	718
Additional capital	84,373	66,500
Retained earnings	1,011,551	745,994
Accumulated other comprehensive loss	(11,715)	(11,358)
Common stock held in treasury, at cost 17,957,855and 16,509,345 shares as of September 30, 2007 and December 31, 2006, respectively	(419,858)	(335,760)
Total stockholders equity	665,075	466,094
Total liabilities and stockholders equity	$ 1,611,713	$ 1,237,869

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)
(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Sales and other revenues	$ 1,208,671	$ 1,172,693	$ 3,351,535	$ 3,085,127
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion, and amortization)	1,059,471	979,309	2,708,422	2,562,803
Operating expenses (exclusive of depreciation, depletion, and amortization)	52,185	54,146	153,430	155,705
General and administrative expenses (exclusive of depreciation, depletion, and amortization)	18,798	12,566	55,993	44,813
Depreciation, depletion and amortization	10,531	9,480	32,623	28,187
Exploration expenses, including dry holes	54	102	311	329
Total operating costs and expenses	1,141,039	1,055,603	2,950,779	2,791,837
Income from operations	67,632	117,090	400,756	293,290
Other income (expense):				
Equity in earnings of Holly Energy Partners	5,564	3,596	13,864	8,324
Interest income	4,368	2,747	10,478	6,890
Interest expense	(297)	(268)	(840)	(815)
	9,635	6,075	23,502	14,399
Income from continuing operations before income taxes	77,267	123,165	424,258	307,689
Income tax provision:				
Current	8,577	37,918	128,524	101,762
Deferred	10,564	6,046	11,439	7,837
	19,141	43,964	139,963	109,599
Income from continuing operations	58,126	79,201	284,295	198,090
Discontinued operations				
Income from discontinued operations		21		7,012
Gain (loss) on sale of discontinued operations		(220)		13,805
Income (loss) from discontinued operations, net of taxes		(199)		20,817

Net income	$	58,126	$	79,002	$	284,295	$	218,907
Basic earnings per share:								
Continuing operations	$	1.06	$	1.40	$	5.17	$	3.45
Discontinued operations								0.36
Net income	$	1.06	$	1.40	$	5.17	$	3.81
Diluted earnings per share:								
Continuing operations	$	1.04	$	1.37	$	5.08	$	3.38
Discontinued operations								0.35
Net income	$	1.04	$	1.37	$	5.08	$	3.73
Cash dividends declared per common share	$	0.12	$	0.08	$	0.34	$	0.21
Average number of common shares outstanding:								
Basic		54,819		56,555		54,988		57,393
Diluted		55,853		57,783		56,017		58,643

See accompanying notes.

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HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	Nine Months Ended September 30,	
	2007	**2006**
Cash flows from operating activities:		
Net income	$ 284,295	$ 218,907
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization (includes discontinued operations)	32,623	28,737
Deferred income taxes (includes discontinued operations)	11,439	5,395
Equity based compensation expense	8,328	3,883
Distributions in excess of equity in earnings in HEP	3,001	6,675
Gain on sale of assets, before income taxes		(22,004)
(Increase) decrease in current assets:		
Accounts receivable	(184,944)	13,531
Inventories	(50,129)	(8,414)
Income taxes receivable	(3,251)	(725)
Prepayments and other	(1,923)	(10,744)
Increase (decrease) in current liabilities:		
Accounts payable	171,752	(17,295)
Accrued liabilities	(128)	9,431
Income taxes payable		(5,354)
Turnaround expenditures		(7,122)
Other, net	(14,363)	(6,630)
Net cash provided by operating activities	256,700	208,271
Cash flows from investing activities:		
Additions to properties, plants and equipment	(113,215)	(89,182)
Net cash proceeds from sale of Montana Refinery		48,872
Purchases of marketable securities	(561,767)	(172,291)
Sales and maturities of marketable securities	394,403	285,943
Net cash provided by (used for) investing activities	(280,579)	73,342
Cash flows from financing activities:		
Issuance of common stock upon exercise of options	607	2,424
Purchase of treasury stock	(84,100)	(138,369)
Cash dividends	(16,651)	(10,475)
Excess tax benefit from equity based compensation	8,940	10,371
Net cash used for financing activities	(91,204)	(136,049)
Cash and cash equivalents:		
Increase (decrease) for the period	(115,083)	145,564

Beginning of period	154,117	49,064
End of period	$ 39,034	$ 194,628
Supplemental disclosure of cash flow information:		
Cash paid during the period for		
Interest	$ 673	$ 510
Income taxes	$ 122,835	$ 112,274

See accompanying notes.

HOLLY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Net income	$ 58,126	$ 79,002	$ 284,295	$ 218,907
Other comprehensive income (loss):				
Securities available for sale:				
Unrealized gain (loss) on available for sale securities	1,114	(332)	1,542	(531)
Reclassification adjustment to net income on sale of equity securities	(41)	(84)	(46)	(94)
Total unrealized gain (loss) on available for sale securities	1,073	(416)	1,496	(625)
Retirement medical obligation adjustment			(2,792)	
Other comprehensive income (loss) before income taxes	1,073	(416)	(1,296)	(625)
Income tax benefit	(18)	(163)	(939)	(244)
Other comprehensive income (loss)	1,091	(253)	(357)	(381)
Total comprehensive income	$ 59,217	$ 78,749	$ 283,938	$ 218,526

See accompanying notes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

NOTE 1: Description of Business and Presentation of Financial Statements

References herein to Holly Corporation include Holly Corporation and its consolidated subsidiaries. In accordance with the Securities and Exchange Commission s (SEC) Plain English guidelines, this Quarterly Report on Form 10-Q has been written in the first person. In this document, the words we , our , ours and us refer only to Holly Corporatio and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

As of the close of business on September 30, 2007, we:

- owned and operated two refineries consisting of a petroleum refinery in Artesia, New Mexico that is operated in conjunction with crude oil distillation and vacuum distillation and other facilities situated 65 miles away in Lovington, New Mexico (collectively known as the Navajo Refinery), and a refinery in Woods Cross, Utah (Woods Cross Refinery);

- owned approximately 800 miles of crude oil pipelines located principally in west Texas and New Mexico;

- owned and operated Holly Asphalt Company (formerly NK Asphalt Partners) which manufactures and markets asphalt products from various terminals in Arizona and New Mexico; and

- owned a 45.0% interest in Holly Energy Partners, L.P. (HEP) which includes our 2% general partner interest, which has logistic assets including approximately 1,700 miles of petroleum product pipelines located in Texas, New Mexico and Oklahoma (including 340 miles of leased pipeline); eleven refined product terminals; two refinery truck rack facilities, a refined products tank farm facility, and a 70% interest in Rio Grande Pipeline Company (Rio Grande).

On March 31, 2006 we sold our petroleum refinery in Great Falls, Montana (the Montana Refinery) to a subsidiary of Connacher Oil and Gas Limited (Connacher). Accordingly, the results of operations of the Montana Refinery and a net gain of $13.8 million on the sale are shown in discontinued operations (see Note 2).

We have prepared these consolidated financial statements without audit. In management s opinion, these consolidated financial statements include all normal recurring adjustments necessary for a fair presentation of our consolidated financial position as of September 30, 2007, the consolidated results of operations and comprehensive income for the three months and nine months ended September 30, 2007 and 2006 and consolidated cash flows for the nine months ended September 30, 2007 and 2006 in accordance with the rules and regulations of the SEC. Although certain notes and other information required by accounting principles generally accepted in the United States have been condensed or omitted, we believe that the disclosures in these consolidated financial statements are adequate to make the information presented not misleading. These consolidated financial statements should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2006 filed with the SEC.

We use the last-in, first-out (LIFO) method of valuing inventory. Under the LIFO method, an actual valuation of inventory can only be made at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management s estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation.

Our results of operations for the nine months ended September 30, 2007 are not necessarily indicative of the results to be expected for the full year. Certain reclassifications, which we determined to be immaterial, have been made to prior reported amounts to conform to current classifications.

New Accounting Pronouncements

EITF No.06-11 Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards

In June 2007, the FASB ratified Emerging Issues Task Force (EITF) Issue No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF No. 06-11 requires that tax benefits generated by dividends paid during the vesting period on certain equity-classified share-based compensation awards be classified as additional paid-in capital and included in a pool of excess tax benefits available to absorb tax deficiencies from share-based payment awards. EITF No. 06-11 is effective for fiscal years beginning after December 15, 2007. While we are currently evaluating the impact of EITF No. 06-11, we do not expect the adoption of this standard to have a material impact on our financial condition, results of operations and cash flows.

SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No 115. SFAS No. 159, which amends SFAS No. 115, allows certain financial assets and liabilities to be recognized, at a company s election, at fair market value, with any gains or losses for the period recorded in the statement of income. SFAS No. 159 includes available-for-sale securities in the assets eligible for this treatment. Currently, we record the gains or losses for the period as a component of comprehensive income and in the equity section of the balance sheet. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, and interim periods in those fiscal years. We do not expect the adoption of this statement to have a material impact on our financial condition, results of operations and cash flows.

Interpretation No. 48 Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We adopted this standard effective January 1, 2007. As a result of the implementation of this standard, we recognized no material adjustment in the liability for unrecognized income tax benefits.

We are subject to U.S. federal income tax and to the income tax of multiple state jurisdictions. We have substantially concluded all U.S. federal, state and local income tax matters for fiscal years through July 31, 2002. In 2006, the Internal Revenue Service commenced examinations of our U.S. federal income tax returns for the tax years ended July 31, 2003 and December 31, 2003. To date, we do not anticipate that the resolution of this audit will result in a material change to our financial condition, results of operations or cash flows.

Our policy is to recognize potential interest and penalties related to income tax matters in income tax expense. We believe we have appropriate support for the income tax positions taken and to be taken on our income tax returns and that our accruals for tax liabilities are adequate for all open years based on an assessment of many factors, including past experience and interpretations of tax law applied to the facts of each matter.

SFAS No. 157 Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this interpretation will have a material impact on our financial condition, results of operations and cash flows.

NOTE 2: Discontinued Operations

On March 31, 2006 we sold the Montana Refinery to Connacher. The net cash proceeds we received on the sale of the Montana Refinery amounted to $48.9 million, net of transaction fees and expenses. Additionally we received 1,000,000 shares of Connacher common stock valued at $4.3 million at March 31, 2006. In accounting for the sale, we recorded a pre-tax gain of $22.4 million. The Montana Refinery assets disposed of had a net book value at March 31, 2006 of $13.7 million for property, plant and equipment, $15.4 million for inventories and $2.0 million for other assets, with current liabilities assumed amounting to $0.3 million.

We retained certain quantities of finished product inventories that were not included in the sale to Connacher. These inventories were liquidated during the second quarter of 2006.
The following tables provide summarized income statement information related to discontinued operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Sales and other revenues from discontinued operations	$	$ 51	$	$ 53,912
Income from discontinued operations before income taxes	$	$ 31	$	$ 11,176
Income tax expense		(10)		(4,164)
Income from discontinued operations, net		21		7,012
Gain (loss) on sale of discontinued operations before income taxes		(354)		22,004
Income tax (expense) benefit		134		(8,199)
Gain (loss) on sale of discontinued operations, net		(220)		13,805
Income (loss) from discontinued operations, net	$	$ (199)	$	$ 20,817

In accordance with the Montana Refinery sale agreement, we retained certain financial liabilities, including certain environmental liabilities related to required remediation and corrective action for environmental conditions that existed at the time of sale and for financial penalties for infractions that occurred prior to the sale. Based on our estimates, we had accruals of $1.3 million as of September 30, 2007 and December 31, 2006 related to such environmental liabilities which is included in our environmental liability accrual as discussed in Note 7.

NOTE 3: Investment in Holly Energy Partners

HEP is a publicly held master limited partnership that commenced operations July 13, 2004 upon the completion of its initial public offering. We currently have a 45% ownership interest in HEP, including our 2% general partner interest. HEP serves our refineries in New Mexico and Utah under a 15-year pipelines and terminals agreement (HEP PTA) expiring in 2019 and a 15-year intermediate pipeline agreement expiring in 2020 (HEP IPA). Under the HEP PTA, we pay HEP fees to transport on their refined product pipelines or throughput in their terminals, volumes of refined products that will result in minimum annual payments to HEP. Following the July 1, 2007 producer price index (PPI) rate adjustment, minimum payments under the HEP PTA will be $39.6 million for the twelve months ending June 30, 2008. Under the HEP IPA, we agreed to transport minimum volumes of intermediate products on the intermediate pipelines that will result in minimum annual payments to HEP. Following the July 1, 2007 PPI rate adjustment, minimum payments under the HEP IPA will be $12.8 million for the twelve months ending June 30, 2008. Minimum payments for both agreements will adjust upward based on increases in the producer price index over the term of the agreements. Additionally, we agreed to indemnify HEP up to an aggregate amount of $17.5 million for any environmental noncompliance and remediation liabilities associated with the assets transferred to HEP and occurring or existing prior to the date of the transfers of ownership to HEP. Of this total, indemnification in excess of $15.0 million relates solely to the intermediate pipelines.
HEP is a variable interest entity (VIE) as defined under FIN 46, and following HEP s acquisition of the intermediate feedstock pipelines in 2005, we determined that our beneficial variable interest in HEP was less than 50%. We report

our share of the earnings of HEP, including any incentive distributions paid through our general partner interest, using the equity method of accounting. HEP has risk associated with its operations. HEP has three major customers, of which we are one. If any of the customers fails to meet the desired shipping levels or terminates

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its contracts, HEP could suffer substantial losses unless a new customer is found. If HEP does suffer losses, we would recognize our percentage of those losses based on our ownership percentage in HEP at that time.

We hold 7,000,000 subordinated units and 70,000 common units of HEP as of September 30, 2007. Our rights as holder of subordinated units to receive distributions of cash from HEP are subordinated to the rights of the common unitholders to receive such distributions.

The following table sets forth the changes in our investment account balance with HEP for the nine months ended September 30, 2007 (In thousands):

Investment in HEP balance at December 31, 2006	$ (164,405)
Equity in the earnings of HEP	13,864
Regular quarterly distributions from HEP	(16,865)
Investment in HEP balance at September 30, 2007	$ (167,406)

The following tables provide summary financial results for HEP.

	September 30, 2007	December 31, 2006
	(In thousands)	
Current assets	$ 20,229	$ 23,624
Properties and equipment, net	154,770	160,484
Transportation agreements and other	57,392	59,465
Total assets	$ 232,391	$ 243,573
Current liabilities	$ 9,594	$ 14,174
Long-term liabilities	182,515	182,210
Minority interest	10,486	10,963
Partners equity	29,796	36,226
Total liabilities and partners equity	$ 232,391	$ 243,573

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Revenues	$ 27,213	$ 22,899	$ 78,216	$ 63,864
Operating costs and expenses	13,008	12,098	38,889	36,723
Operating income	14,205	10,801	39,327	27,141
Other expenses, net	(3,515)	(3,050)	(10,197)	(9,257)
Net income	$ 10,690	$ 7,751	$ 29,130	$ 17,884

We have related party transactions with HEP for pipeline and terminal expenses, certain employee costs, insurance costs, and administrative costs under the HEP PTA, HEP IPA and an Omnibus Agreement.

Pipeline and terminal expenses paid to HEP were $14.8 million and $14.3 million for the three months ended September 30, 2007 and 2006, respectively, and $44.9 million and $37.3 million for the nine months ended September 30, 2007 and 2006, respectively.

For the three and nine months ended September 30, 2007, we purchased from HEP, $2.7 million of inventory of accumulated terminal overages of refined product. These overages arose from net product gains at HEP s terminals from the beginning of 2005 through the third quarter of 2007. We are currently negotiating an amendment to our pipelines and terminals agreement with HEP that provides that such terminal overages of refined product shall belong to us in the future.

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We charged HEP $0.6 million and $0.5 million for the three months ended September 30, 2007 and 2006, respectively, and $1.6 million and $1.5 million for the nine months ended September 30, 2007 and 2006, respectively, for general and administrative services under the Omnibus Agreement which we recorded as a reduction in expenses.

HEP reimbursed us for costs of employees supporting their operations of $2.0 million for the three months ended September 30, 2007 and 2006, and $6.6 million and $5.7 million for the nine months ended September 30, 2007 and 2006, respectively, which we recorded as a reduction in expenses.

We reimbursed HEP $80,000 and $42,000 for the three months ended September 30, 2007 and 2006, respectively, and $179,000 and $138,000 for the nine months ended September 30, 2007 and 2006, respectively, for certain costs paid on our behalf.

We received as regular distributions on our subordinated units, common units and general partner interest, $5.8 million and $5.2 million for the three months ended September 30, 2007 and 2006, respectively, and $16.9 million and $15.0 million for the nine months ended September 30, 2007 and 2006, respectively. Our distributions for the three months ended September 30, 2007 and 2006 included $0.6 million and $0.3 million, respectively, in incentive distributions with respect to our general partner interest. General partner incentive distributions of $1.5 million and $0.8 million were included in our distributions for the nine months ended September 30, 2007 and 2006, respectively.

We had a related party receivable from HEP of $1.5 million and $2.2 million at September 30, 2007 and December 31, 2006, respectively.

We had accounts payable to HEP of $7.6 million and $5.7 million at September 30, 2007 and December 31, 2006, respectively.

Prepayments and other includes $1.2 million and $0.2 million at September 30, 2007 and December 31, 2006, respectively, related to minimum payments under the HEP IPA which may be applied as credits against future billings from HEP if our shipments exceed the minimum volume commitments on the intermediate pipelines.

NOTE 4: Earnings Per Share

Basic earnings per share from continuing operations is calculated as income from continuing operations divided by the average number of shares of common stock outstanding. Diluted earnings per share from continuing operations assumes, when dilutive, the issuance of the net incremental shares from stock options, variable restricted shares and performance share units. The following is a reconciliation of the denominators of the basic and diluted per share computations for income from continuing operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands, except per share data)			
Income from continuing operations	$ 58,126	$ 79,201	$ 284,295	$ 198,090
Average number of shares of common stock outstanding	54,819	56,555	54,988	57,393
Effect of dilutive stock options, variable restricted shares and performance share units	1,034	1,228	1,029	1,250
	55,853	57,783	56,017	58,643

Average number of shares of common stock outstanding assuming dilution				
Basic earnings per share from continuing operations	$ 1.06	$ 1.40	$ 5.17	$ 3.45
Diluted earnings per share from continuing operations	$ 1.04	$ 1.37	$ 5.08	$ 3.38

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NOTE 5: Stock-Based Compensation

On September 30, 2007 we had three principal share-based compensation plans, which are described below. The compensation cost recognized under these plans was $0.6 million and $3.1 million for the three months ended September 30, 2007 and 2006, respectively, and $9.7 million and $14.0 million for the nine months ended September 30, 2007 and 2006, respectively. The total income tax benefit recognized in our consolidated statements of income for share-based compensation arrangements was $0.2 million and $1.2 million for the three months ended September 30, 2007 and 2006, respectively, and $3.8 million and $5.4 million for the nine months ended September 30, 2007 and 2006, respectively. It is currently our practice to issue new shares for settlement of option exercises, restricted stock grants or performance share units settled in stock. Our current accounting policy for the recognition of compensation expense on awards with pro-rata vesting (substantially all of our awards) is to expense the costs pro-rata over the vesting periods. At September 30, 2007, 2,546,159 shares of common stock were reserved for future grants under the current long-term incentive compensation plan, which reservation allows for awards of options, restricted stock, or other performance awards.

Previously awarded stock options and all other compensation arrangements based on the market value of our common stock have been adjusted to reflect the two-for-one stock split effective June 1, 2006.

Stock Options

Under our Long-Term Incentive Compensation Plan and a previous stock option plan, we have granted stock options to certain officers and other key employees. All the options have been granted at prices equal to the market value of the shares at the time of the grant and normally expire on the tenth anniversary of the grant date. These awards generally vest 20% at the end of each of the five years following the grant date. There have been no options granted since December 2001. The fair value on the date of grant of each option awarded was estimated using the Black-Scholes option pricing model.

A summary of option activity and changes during the nine months ended September 30, 2007 is presented below:

Options	Shares	Weighted Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2007	1,576,800	$ 2.25		
Exercised	(189,600)	3.19		
Forfeited or expired				
Outstanding at September 30, 2007	1,387,200	$ 2.12	2.4	$ 80,053
Exercisable at September 30, 2007	1,387,200	$ 2.12	2.4	$ 80,053

The total intrinsic value of options exercised during the nine months ended September 30, 2007 and 2006, was $12.0 million and $27.1 million, respectively.

At September 30, 2007 and December 31, 2006, all stock options granted were fully vested. The total fair value of shares vested during the nine months ended September 30, 2006 was $0.3 million.

Cash received from option exercises under the stock option plans for the nine months ended September 30, 2007 and 2006, was $0.6 million and $2.4 million, respectively. The actual tax benefit realized for the tax deductions from option exercises under the stock option plans totaled $4.7 million and $10.4 million for the nine months ended September 30, 2007 and 2006, respectively.

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Restricted Stock

Under our Long-Term Incentive Compensation Plan, we grant certain officers, other key employees and outside directors restricted stock awards with substantially all awards vesting generally over a period of one to five years. Although ownership of the shares does not transfer to the recipients until after the shares vest, recipients have dividend rights on these shares from the date of grant. The vesting for certain key executives is contingent upon certain earnings per share targets being realized. The fair value of each share of restricted stock awarded, including the shares issued to the key executives, was measured based on the market price as of the date of grant and is being amortized over the respective vesting period.

A summary of restricted stock grant activity and changes during the nine months ended September 30, 2007 is presented below:

Restricted Stock	Grants	Weighted Average Grant-Date Fair Value	Aggregate Intrinsic Value ($000)
Outstanding at January 1, 2007 (nonvested)	494,922	$ 15.07	
Vesting and transfer of ownership to recipients	(253,802)	13.35	
Granted	70,158	59.13	
Forfeited	(21,687)	25.54	
Outstanding at September 30, 2007 (nonvested)	289,591	$ 26.46	$ 17,326

The total intrinsic value of restricted stock vested and transferred to recipients during the nine months ended September 30, 2007 and 2006 was $15.2 million and $5.5 million, respectively. As of September 30, 2007, there was $3.2 million of total unrecognized compensation cost related to nonvested restricted stock grants. That cost is expected to be recognized over a weighted-average period of 1.0 years. The total fair value of shares vested during the nine months ended September 30, 2007 and 2006 was $3.4 million and $1.0 million, respectively.

Performance Share Units

Under our Long-Term Incentive Compensation Plan, we grant certain officers and other key employees performance share units, which are payable in either cash or stock upon meeting certain criteria over the service period, and generally vest over a period of one to three years. Under the terms of our performance share unit grants, awards are subject to either a financial performance or a market performance criteria.

During the 2007 first quarter, we granted 42,813 performance share units with a fair value based on our grant date closing stock price of $55.47. In the third quarter of 2007, we granted an additional 2,450 performance share units having a grant date closing stock price of $74.19. These units are payable in stock and are subject to certain financial performance criteria.

The fair value of each performance share unit award subject to the financial performance criteria and payable in stock is computed using the grant date closing stock price of each respective award grant and will apply to the number of units ultimately awarded. The number of shares ultimately issued for each award will be based on our financial performance as compared to peer group companies over the performance period and can range from zero to 200%. As of September 30, 2007, estimated share payouts for outstanding nonvested performance share unit awards ranged from 150% to 200%.

The fair value of each performance share unit award based on market performance criteria and payable in stock is computed based on an expected-cash-flow approach. The analysis utilizes the grant date closing stock price, dividend yield, historical total returns, expected total returns based on a capital asset pricing model methodology, standard deviation of historical returns and comparison of expected total returns with the peer group. The expected total return and historical standard deviation are applied to a lognormal expected return distribution in a Monte Carlo simulation model to identify the expected range of potential returns and probabilities of expected returns.

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The fair value of each performance share unit award payable in cash is computed quarterly using an expected-cash-flow approach. The analysis utilizes the current stock price, dividend yield, historical total returns as of the measurement date, expected total returns based on a capital asset pricing model methodology, standard deviation of historical returns and comparison of expected total returns with the peer group. The expected total return and historical standard deviation are applied to a lognormal expected return distribution in a Monte Carlo simulation model to identify the expected range of potential returns and probabilities of expected returns.

At September 30, 2007, the price of our stock was $59.83, the latest quarterly dividend was $0.12, and the risk-free rate was 4.89%. The inputs affecting the expected total return for us and the peer group are based on a capital asset pricing model utilizing information available at the measurement date. The monthly standard deviation of returns is based on the standard deviation of historical return information. The expected return and standard deviation are presented below:

Company	Expected Return on Equity	Standard Deviation (Monthly)
Holly	13.3%	13.1%
Peer group	11.0% to 13.3%	9.4% to 15.2%

A summary of performance share units activity and changes during the nine months ended September 30, 2007 is presented below:

	Market Performance		Financial Performance	
Performance Share Units	Payable in Cash Grants	Stock Settled Grants	Stock Settled Grants	Total Performance Share Units
Outstanding at January 1, 2007 (nonvested)	227,350	125,774	74,928	428,052
Vesting and payment of benefit to recipients	(145,900)	(75,500)		(221,400)
Granted			45,263	45,263
Forfeited		(7,800)	(10,063)	(17,863)
Outstanding at September 30, 2007 (nonvested)	81,450	42,474	110,128	234,052

For the nine months ended September 30, 2007 we paid $15.5 million in cash and issued 75,500 shares of our common stock having a fair value of $3.7 million related to vested performance share units. As of September 30, 2007, the cash liability associated with nonvested performance share units was $8.9 million and is recorded in Accrued liabilities in our consolidated balance sheets. At September 30, 2007, there was a total of $5.0 million of unrecognized compensation cost related to nonvested performance share units. This total consists of unrecognized compensation costs of $4.1 million related to stock-settled performance units having a weighted average grant date fair value of $37.29 and $0.9 million related to cash-settled performance units having a weighted average fair value of $119.42. These costs are expected to be recognized over a weighted-average period of 1.3 years.

NOTE 6: Cash and Cash Equivalents and Investments in Marketable Securities

Our investment portfolio consists of cash, cash equivalents, and investments in debt securities primarily issued by government entities. In addition, as part of the sale of the Montana Refinery, we received 1,000,000 shares of Connacher common stock.

We invest in highly-rated marketable debt securities, primarily issued by government entities that have maturities at the date of purchase of greater than three months. These securities include investments in variable rate demand notes (VRDN) and auction rate securities (ARS). Although VRDN and ARS may have long-term stated maturities, generally 15 to 30 years, we have designated these securities as available-for-sale and have classified them as current because we view them as available to support our current operations. Rates on VRDN are typically reset either daily or weekly. Rates on ARS are reset through a Dutch auction process at intervals between 35 and 90 days, depending on the terms of the security. VRDN and ARS may be liquidated at par on the rate reset date. We also invest in other

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marketable debt securities with the maximum maturity of any individual issue not greater than two years from the date of purchase. All of these instruments are classified as available-for-sale, and as a result, are reported at fair value. Interest income is recorded as earned. Unrealized gains and losses, net of related income taxes, are temporary and reported as a component of accumulated other comprehensive income. Upon sale, realized gains and losses on the sale of marketable securities are computed based on the specific identification of the underlying cost of the securities sold and the unrealized gains and losses previously reported in other comprehensive income are reclassified to current earnings.

The following is a summary of our available-for-sale securities at September 30, 2007:

	Available-for-Sale Securities		
	Amortized Cost	**Gross Unrealized Gains (Losses)**	**Estimated Fair Value (Net Carrying Amount)**
		(In thousands)	
States and political subdivisions	$ 266,273	$ 403	$ 266,676
Equity securities	4,328	(308)	4,020
Total marketable securities	$ 270,601	$ 95	$ 270,696

Interest income on our marketable debt securities for the nine months ended September 30, 2007 and 2006 included $7.1 million and $4.5 million, respectively, of interest earned, $46,000 and $94,000, respectively, in realized gains and amortization of $0.8 million and $1.4 million, respectively, in net premiums paid related to our marketable debt securities. We had 173 and 232 sales and maturities during the nine months ended September 30, 2007 and 2006, respectively, in which we received a total of $394.4 million and $285.9 million, respectively. The realized gains represent the difference between the purchase price, as amortized, and the market value on the maturity or sales date.

NOTE 7: Environmental

Consistent with our accounting policy for environmental remediation costs, we expensed $0 and $0.4 million for the three months ended September 30, 2007 and 2006, respectively, and $2.3 million and $3.6 million for the nine months ended September 30, 2007 and 2006, respectively, for environmental remediation obligations. The accrued environmental liability reflected in the consolidated balance sheets was $9.0 million and $7.6 million at September 30, 2007 and December 31, 2006, respectively, of which $6.2 million and $6.1 million, respectively, were classified as other long-term liabilities. Costs of future expenditures for environmental remediation are not discounted to their present value.

NOTE 8: Debt

Credit Facility

We have a $175.0 million secured revolving credit facility with Bank of America as administrative agent and lender, with a term of four years and an option to increase the facility to $225.0 million subject to certain conditions. This credit facility expires in 2008 and may be used to fund working capital requirements, capital expenditures, acquisitions or other general corporate purposes. We were in compliance with all covenants at September 30, 2007. At September 30, 2007, we had outstanding letters of credit totaling $2.5 million, and no outstanding borrowings under our credit facility. At that level of usage, the unused commitment under our credit facility was $172.5 million at September 30, 2007.

We made cash interest payments of $0.7 million and $0.5 million for the nine months ended September 30, 2007 and 2006, respectively.

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NOTE 9: Income Taxes

The effective tax rate for continuing operations was 33.0% and 35.6% for the nine months ending September 30, 2007 and 2006, respectively. The decrease in our effective tax rate was principally due to a statutory increase in the federal tax deduction for domestic manufacturing activities and an increase in the low sulfur diesel fuel production tax credit.

NOTE 10: Stockholders Equity

Two-For-One Stock Split: On May 11, 2006, we announced that our Board of Directors approved a two-for-one stock split payable in the form of a stock dividend of one share of common stock for each issued and outstanding share of common stock. The stock dividend was paid on June 1, 2006 to all holders of record of common stock at the close of business on May 22, 2006.

All references to the number of shares of common stock and per share amounts for all periods presented have been adjusted to reflect the split on a retrospective basis.

Common Stock Repurchases: On August 9, 2007, we announced that our Board of Directors had authorized a $100.0 million increase to our current common stock repurchase program increasing the authorized stock repurchase limit from $300.0 million to $400.0 million. Common stock repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. During the nine months ended September 30, 2007, we repurchased 1,327,090 shares at a cost of $79.0 million or an average of $59.55 per share under this repurchase initiative. Since inception of this repurchase initiative in November 2005 through September 30, 2007, we have repurchased 6,773,297 shares at a cost of $286.0 million or an average of $42.22 per share.

During the nine months ended September 30, 2007, we repurchased at current market price from certain officers and other key employees 121,420 shares of our common stock at a cost of $5.1 million. These purchases were made under the terms of restricted stock and performance share unit agreements to provide funds for the payment of payroll and income taxes due at the vesting of restricted shares in the case of officers and employees who did not elect to satisfy such taxes by other means.

NOTE 11: Other Comprehensive Income

The components and allocated tax effects of other comprehensive income (loss) are as follows:

	Before-Tax	Tax Expense (Benefit)	After-Tax
		(In thousands)	
For the three months ended September 30, 2007			
Unrealized gain on available-for-sale securities	$ 1,073	$ (18)	$ 1,091
Other comprehensive income	$ 1,073	$ (18)	$ 1,091
For the three months ended September 30, 2006			
Unrealized loss on available-for-sale securities	$ (416)	$ (163)	$ (253)
Other comprehensive loss	$ (416)	$ (163)	$ (253)
For the nine months ended September 30, 2007			
Retirement medical obligation adjustment	$ (2,792)	$ (1,086)	$ (1,706)
Unrealized gain on available-for-sale securities	1,496	147	1,349
Other comprehensive loss	$ (1,296)	$ (939)	$ (357)

For the nine months ended September 30, 2006			
Unrealized loss on available-for-sale securities	$ (625)	$ (244)	$ (381)
Other comprehensive loss	$ (625)	$ (244)	$ (381)

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Unrealized gains and losses are due to changes in market values of our available-for-sale securities and are temporary in nature.

Accumulated other comprehensive loss in the equity section of our consolidated balance sheets includes:

	September 30, 2007	December 31, 2006
	(In thousands)	
Pension obligation adjustment	$ (1,115)	$ (1,115)
Unrealized gain (loss) on available-for-sale securities	493	(856)
Adjustment to apply adoption of SFAS No. 158, net of income tax effect of $8,149 and $7,063, respectively	(11,093)	(9,387)
Accumulated other comprehensive loss	$ (11,715)	$ (11,358)

NOTE 12: Retirement Plan

We have a non-contributory defined benefit retirement plan that covers most of our employees who were hired prior to January 1, 2007. Our policy is to make contributions annually of not less than the minimum funding requirements of the Employee Retirement Income Security Act of 1974. Benefits are based on the employee s years of service and compensation.

The net periodic pension expense consisted of the following components:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Service cost	$ 1,027	$ 1,022	$ 3,082	$ 3,248
Interest cost	1,019	1,018	3,056	3,115
Expected return on assets	(1,020)	(863)	(3,059)	(2,611)
Amortization of prior service cost	98	63	293	196
Amortization of net loss	227	217	681	825
One time cost incurred with sale of Montana Refinery				300
Net periodic benefit cost	$ 1,351	$ 1,457	$ 4,053	$ 5,073

The expected long-term annual rate of return on plan assets is 8.5%. This rate was used in measuring 2007 and 2006 net periodic benefit cost. We contributed $10.0 million to the retirement plan in the third quarter of 2007.

NOTE 13: Contingencies

On May 29, 2007, the United States Court of Appeals for the District of Columbia Circuit (Court of Appeals) issued its decision on petitions for review, brought by us and other parties, concerning rulings by the Federal Energy Regulatory Commission (FERC) in proceedings brought by us and other parties against SFPP. These proceedings relate to tariffs of common carrier pipelines, which are owned and operated by SFPP, for shipments of refined products from El Paso, Texas to Tucson and Phoenix, Arizona and from points in California to points in Arizona. We are one of several refiners that regularly utilize an SFPP pipeline to ship refined products from El Paso, Texas to Tucson and Phoenix, Arizona. The Court of Appeals in its May 29, 2007 decision approved a FERC position, which is adverse to us, on the treatment of income taxes in the calculation of allowable rates for pipelines operated by partnerships and ruled in our favor on an issue relating to our rights to reparations when it is determined that certain tariffs we paid to SFPP in the past were too high. We currently estimate that, as a result of this decision and prior rulings by the Court of Appeals and the FERC in these proceedings, a net amount will be due from SFPP to us for the

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years 1992 through August 31, 2006 in addition to the $15.3 million we received in 2003 from SFPP as reparations for the period from 1992 through July 2000. Because proceedings in the FERC following the Court of Appeals decision have not been completed and because the decision of the Court of Appeals could be the subject of petitions by one or more parties seeking United States Supreme Court review of issues addressed, it is not possible at this time to determine what will be the net amount payable to us at the conclusion of these proceedings. We and other shippers are currently engaged in settlement discussions with SFPP on remaining issues in the FERC proceedings. These discussions have achieved an agreement for partial settlement relating to shipments from El Paso to Tucson and Phoenix for the period from June 1, 2006 through November 30, 2007. If approved by the FERC, the settlement would leave for resolution in pending proceedings all remaining issues for other periods.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have Federal Clean Air Act liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo Refinery and previously-owned Montana Refinery. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refinery. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement.

On December 6, 2006, the Montana Department of Environment Quality (MDEQ) filed in state district court in Great Falls, Montana a Complaint and Application for Preliminary injunction (the Complaint) naming as defendants Montana Refining Company (MRC), our subsidiary that owned the Great Falls. Montana refinery until it was sold to an unrelated purchaser on March 31, 2006, and the unrelated company that purchased the refinery from MRC. The MDEQ assets in the Complaint that the Great Falls refinery exceeded limitations on sulfur dioxide in the refinery s air emission permit on certain dates in 2004 and 2005 and in 2006 both before and after the sale of the refinery, erroneously certified compliance with limitations on sulfur dioxide emissions failed to promptly report emissions limit deviations, exceeded limits on sulfur in fuel gas on specified dates in 2005, failed in 2005 to conduct timely testing for certain emissions, submitted late a report required to be submitted in early 2006, failed to achieve a specified limitation on certain emissions in the first three quarters of 2006, and failed to timely submit a report on a 2005 emissions test. The Complaint seeks penalties under applicable law of up to $10,000 per violation and an order enjoining MRC and the current owner of the refinery from further violations. While we do not agree with a number of the violations asserted in the Complaint, we and the current owner of the Great Falls refinery have been in negotiations with the MDEQ both before and after the filing of the Complaint to attempt to settle the issues raised on a compromise basis. At the date of this report, we have negotiated a tentative settlement agreement, which has not yet been put into a final written agreement, under which we would make payments totaling approximately $100,000.

We are a party to various other litigation and proceedings not mentioned in this report which we believe, based on advice of counsel, will not have a materially adverse impact on our financial condition, results of operations or cash flows.

Note 14: Subsequent Events

On October 15, 2007, we entered into an agreement with HEP that amends the HEP PTA under which HEP has agreed to expand their refined products pipeline system between Artesia, New Mexico and El Paso, Texas (the South System). The amendment also provides for a tariff increase, effective May 1, 2008, on our shipments on HEP s refined product pipelines and monetary incentives to HEP for the early completion of the South System expansion, currently targeted for January 31, 2009.

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

This Item 2 contains forward-looking statements. See Forward-Looking Statements at the beginning of Part I of this Quarterly Report on Form 10-Q. In this document, the words we , our and us refer only to Holly Corporation and its consolidated subsidiaries or to Holly Corporation or an individual subsidiary and not to any other person.

OVERVIEW

We are principally an independent petroleum refiner operating two refineries in Artesia and Lovington, New Mexico (operated as one refinery and collectively known as the Navajo Refinery) and Woods Cross, Utah (the Woods Cross Refinery). As of September 30, 2007, our refineries had a combined crude capacity of 111,000 BPSD. Our profitability depends largely on the spread between market prices for refined petroleum products and crude oil prices.

At September 30, 2007, we also owned a 45% interest in Holly Energy Partners, L.P. (HEP), which owns and operates pipeline and terminalling assets and owns a 70% interest in Rio Grande Pipeline Company (Rio Grande).

Our principal source of revenue is from the sale of high value light products such as gasoline, diesel fuel and jet fuel in markets in the southwestern and western United States. Our sales and other revenues and net income for the nine months ended September 30, 2007 were $3,351.5 million and $284.3 million, respectively. Our sales and other revenues and net income for the nine months ended September 30, 2006 were $3,085.1 million and $218.9 million, respectively. Our principal expenses are costs of products sold and operating expenses. Our total operating costs and expenses for the nine months ended September 30, 2007 were $2,950.8 million, as compared to $2,791.8 million for the nine months ended September 30, 2006.

On March 31, 2006 we sold our petroleum refinery in Great Falls, Montana (the Montana Refinery) to a subsidiary of Connacher Oil and Gas Limited (Connacher). The net cash proceeds we received on the sale of the Montana Refinery amounted to $48.9 million, net of transaction fees and expenses. Additionally we received 1,000,000 shares of Connacher common stock valued at approximately $4.3 million at March 31, 2006. We have presented in discontinued operations the results of operations and a net gain of $13.8 million on the sale.

On August 9, 2007, we announced that our Board of Directors had authorized a $100.0 million increase to our current common stock repurchase program increasing the authorized stock repurchase limit from $300.0 million to $400.0 million. Common stock repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. During the nine months ended September 30, 2007, we repurchased under this repurchase initiative 1,327,090 shares at a cost of $79.0 million or an average of $59.55 per share. Since inception of this repurchase initiative in November 2005 through September 30, 2007, we have repurchased 6,773,297 shares at a cost of $286.0 million or an average of $42.22 per share.

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RESULTS OF OPERATIONS
Financial Data (Unaudited)

	Three Months Ended September 30,		Change from 2006	
	2007	2006	Change	Percent
	(In thousands, except per share data)			
Sales and other revenues	$ 1,208,671	$ 1,172,693	$ 35,978	3.1%
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion and amortization)	1,059,471	979,309	80,162	8.2
Operating expenses (exclusive of depreciation, depletion and amortization)	52,185	54,146	(1,961)	(3.6)
General and administrative expenses (exclusive of depreciation, depletion and amortization)	18,798	12,566	6,232	49.6
Depreciation, depletion and amortization	10,531	9,480	1,051	11.1
Exploration expenses, including dry holes	54	102	(48)	(47.1)
Total operating costs and expenses	1,141,039	1,055,603	85,436	8.1
Income from operations	67,632	117,090	(49,458)	(42.2)
Other income (expense):				
Equity in earnings of HEP	5,564	3,596	1,968	54.7
Interest income	4,368	2,747	1,621	59.0
Interest expense	(297)	(268)	(29)	10.8
	9,635	6,075	3,560	58.6
Income from continuing operations before income taxes	77,267	123,165	(45,898)	(37.3)
Income tax provision	19,141	43,964	(24,823)	(56.5)
Income from continuing operations	58,126	79,201	(21,075)	(26.6)
Income from discontinued operations, net of taxes		(199)	199	(100.0)
Net income	$ 58,126	$ 79,002	$ (20,876)	(26.4)%
Basic earnings per share:				
Continuing operations	$ 1.06	$ 1.40	$ (0.34)	(24.3)%
Discontinued operations				
Net income	$ 1.06	$ 1.40	$ (0.34)	(24.3)%
Diluted earnings per share:				
Continuing operations	$ 1.04	$ 1.37	$ (0.33)	(24.1)%
Discontinued operations				

Net income	$	1.04	$	1.37	$	(0.33)	(24.1)%
Cash dividends declared per common share	$	0.12	$	0.08	$	0.04	50.0%
Average number of common shares outstanding:							
Basic		54,819		56,555		(1,736)	(3.1)%
Diluted		55,853		57,783		(1,930)	(3.3)%

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	Nine Months Ended September 30,		Change from 2006	
	2007	2006	Change	Percent
	(In thousands, except per share data)			
Sales and other revenues	$ 3,351,535	$ 3,085,127	$ 266,408	8.6%
Operating costs and expenses:				
Cost of products sold (exclusive of depreciation, depletion and amortization)	2,708,422	2,562,803	145,619	5.7
Operating expenses (exclusive of depreciation, depletion and amortization)	153,430	155,705	(2,275)	(1.5)
General and administrative expenses (exclusive of depreciation, depletion and amortization)	55,993	44,813	11,180	24.9
Depreciation, depletion and amortization	32,623	28,187	4,436	15.7
Exploration expenses, including dry holes	311	329	(18)	(5.5)
Total operating costs and expenses	2,950,779	2,791,837	158,942	5.7
Income from operations	400,756	293,290	107,466	36.6
Other income (expense):				
Equity in earnings of HEP	13,864	8,324	5,540	66.6
Interest income	10,478	6,890	3,588	52.1
Interest expense	(840)	(815)	(25)	3.1
	23,502	14,399	9,103	63.2
Income from continuing operations before income taxes	424,258	307,689	116,569	37.9
Income tax provision	139,963	109,599	30,364	27.7
Income from continuing operations	284,295	198,090	86,205	43.5
Income from discontinued operations, net of taxes		20,817	(20,817)	(100.0)
Net income	$ 284,295	$ 218,907	$ 65,388	29.9%
Basic earnings per share:				
Continuing operations	$ 5.17	$ 3.45	$ 1.72	49.9%
Discontinued operations		0.36	(0.36)	(100.0)
Net income	$ 5.17	$ 3.81	$ 1.36	35.7%
Diluted earnings per share:				
Continuing operations	$ 5.08	$ 3.38	$ 1.70	50.3%
Discontinued operations		0.35	(0.35)	(100.0)
Net income	$ 5.08	$ 3.73	$ 1.35	36.2%

Cash dividends declared per common share	$ 0.34	$ 0.21	$ 0.13	61.9%
Average number of common shares outstanding:				
Basic	54,988	57,393	(2,405)	(4.2)%
Diluted	56,017	58,643	(2,626)	(4.5)%

Balance Sheet Data (Unaudited)

	September 30, 2007	December 31, 2006
	(In thousands)	
Cash, cash equivalents and investments in marketable securities	$ 309,730	$ 255,953
Working capital	$ 279,198	$ 240,181
Total assets	$1,611,713	$1,237,869
Stockholders equity	$ 665,075	$ 466,094

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Other Financial Data (Unaudited)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In thousands)			
Net cash provided by (used for) operating activities	$(23,884)	$128,476	$ 256,700	$ 208,271
Net cash provided by (used for) investing activities	$ (6,158)	$ (2,786)	$(280,579)	$ 73,342
Net cash used for financing activities	$(38,061)	$ (48,918)	$ (91,204)	$(136,049)
Capital expenditures	$ 40,684	$ 21,688	$ 113,215	$ 89,182
EBITDA from continuing operations (1)	$ 83,727	$130,166	$ 447,243	$ 329,801

(1) Earnings before interest, taxes, depreciation and amortization, which we refer to as EBITDA, is calculated as net income plus (i) interest expense net of interest income, (ii) income tax provision, and (iii) depreciation, depletion and amortization. EBITDA is not a calculation provided for under accounting principles generally accepted in the United States; however, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should

not be considered as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for financial covenants. We are reporting EBITDA from continuing operations. EBITDA presented above is reconciled to net income under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 3 of Part I of this

Form 10-Q.

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Refining Operating Data (Unaudited)

Our refinery operations include the Navajo Refinery and the Woods Cross Refinery. The following tables set forth information, including non-GAAP performance measures about our consolidated refinery operations. The cost of products and refinery gross margin do not include the effect of depreciation, depletion and amortization. Reconciliations to amounts reported under GAAP are provided under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 3 of Part I of this Form 10-Q.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Navajo Refinery				
Crude charge (BPD) (1)	76,100	75,610	78,550	69,520
Refinery production (BPD) (2)	81,110	82,190	86,030	76,310
Sales of produced refined products (BPD)	80,500	80,950	85,500	75,680
Sales of refined products (BPD) (3)	99,000	96,688	98,740	90,495
Refinery utilization (4)	89.5%	92.2%	93.9%	89.9%
Average per produced barrel (5)				
Net sales	$ 88.46	$ 84.49	$ 85.88	$ 83.21
Cost of products (6)	77.80	68.40	67.32	66.16
Refinery gross margin	10.66	16.09	18.56	17.05
Refinery operating expenses (7)	4.69	4.89	4.37	5.00
Net operating margin	$ 5.97	$ 11.20	$ 14.19	$ 12.05
Feedstocks:				
Sour crude oil	84%	79%	79%	81%
Sweet crude oil	8%	10%	9%	8%
Other feedstocks and blends	8%	11%	12%	11%
Total	100%	100%	100%	100%
Sales of produced refined products:				
Gasolines	57%	58%	58%	59%
Diesel fuels	31%	31%	30%	28%
Jet fuels	3%	3%	3%	4%
Fuel oil	3%	2%	3%	3%
Asphalt	3%	3%	3%	3%
LPG and other	3%	3%	3%	3%
Total	100%	100%	100%	100%
Woods Cross Refinery				
Crude charge (BPD) (1)	22,130	24,360	24,180	24,130

Refinery production (BPD) [(2)]	22,580	25,790	25,460	25,620
Sales of produced refined products (BPD)	25,250	25,160	26,490	25,320
Sales of refined products (BPD) [(3)]	25,550	25,860	26,760	26,360
Refinery utilization [(4)]	85.1%	93.7%	93.0%	92.8%
Average per produced barrel [(5)]				
Net sales	$ 93.06	$ 94.88	$ 86.69	$ 85.33
Cost of products [(6)]	73.27	71.82	64.91	67.56
Refinery gross margin	19.79	23.06	21.78	17.77
Refinery operating expenses [(7)]	5.01	5.18	4.66	5.01
Net operating margin	$ 14.78	$ 17.88	$ 17.12	$ 12.76

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	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
Woods Cross Refinery				
Feedstocks:				
Sour crude oil	2%	%	2%	3%
Sweet crude oil	92%	92%	90%	89%
Other feedstocks and blends	6%	8%	8%	8%
Total	100%	100%	100%	100%
Sales of produced refined products:				
Gasolines	59%	65%	60%	64%
Diesel fuels	30%	29%	29%	28%
Jet fuels	3%	2%	2%	2%
Fuel oil	6%	4%	6%	5%
Asphalt	1%	%	1%	%
LPG and other	1%	%	2%	1%
Total	100%	100%	100%	100%
Consolidated				
Crude charge (BPD) (1)	98,230	99,970	102,730	93,650
Refinery production (BPD) (2)	104,610	107,980	111,800	101,930
Sales of produced refined products (BPD)	105,750	106,110	111,990	101,000
Sales of refined products (BPD) (3)	124,550	122,548	125,500	116,855
Refinery utilization (4)	88.5%	92.6%	93.7%	90.6%
Average per produced barrel (5)				
Net sales	$ 89.56	$ 86.96	$ 86.07	$ 83.74
Cost of products (6)	76.72	69.21	66.75	66.51
Refinery gross margin	12.84	17.75	19.32	17.23
Refinery operating expenses (7)	4.77	4.96	4.44	5.00
Net operating margin	$ 8.07	$ 12.79	$ 14.88	$ 12.23
Feedstocks:				
Sour crude oil	66%	60%	61%	61%
Sweet crude oil	26%	30%	28%	28%
Other feedstocks and blends	8%	10%	11%	11%
Total	100%	100%	100%	100%

Sales of produced refined products:				
Gasolines	57%	60%	59%	60%
Diesel fuels	31%	30%	29%	28%
Jet fuels	3%	2%	3%	4%
Fuel oil	4%	3%	4%	4%
Asphalt	3%	3%	2%	2%
LPG and other	2%	2%	3%	2%
Total	100%	100%	100%	100%

(1) Crude charge represents the barrels per day of crude oil processed at the crude units at our refineries.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery feedstocks through the crude units and other conversion units at our refineries.

(3) Includes refined products purchased for resale.

(4) Represents crude charge divided by total crude capacity (BPSD).

(5) Represents average per barrel amount for produced

refined products sold, which is a non-GAAP measure. Reconciliations to amounts reported under GAAP are located under Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 3 of Part I of this Form 10-Q.

(6) Transportation costs billed from HEP are included in cost of products.

(7) Represents operating expenses of our refinery, exclusive of depreciation, depletion and amortization, and excludes refining segment expenses of product pipelines and terminals.

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Results of Operations Three Months Ended September 30, 2007 Compared to Three Months Ended September 30, 2006

Summary

Income from continuing operations was $58.1 million ($1.06 per basic and $1.04 per diluted share) for the third quarter of 2007, compared to income from continuing operations of $79.2 million ($1.40 per basic and $1.37 per diluted share) for the third quarter of 2006. Income from continuing operations decreased $21.1 million for the third quarter of 2007, a decrease of 27%, as compared to the third quarter of 2006, due principally to a decline in refined product margins in the current year s third quarter. Also affecting income from continuing operations were the effects of increased general and administrative expenses and depreciation, depletion and amortization, partially offset by a decrease in operating costs. Overall sales of produced refined products from continuing operations were relatively flat for the third quarter of 2007 as compared to the same period in 2006 due to a decrease in refinery production during the current year s third quarter. Overall refinery gross margins from continuing operations were $12.84 per produced barrel for the third quarter of 2007 compared to refinery gross margins from continuing operations of $17.75 per produced barrel for the third quarter of 2006.

During August 2007, certain units at our Navajo Refinery were down for 10 days of unscheduled repairs as a result of damage incurred from a power outage. This combined with downtime at our Woods Cross Refinery during the third quarter of 2007 resulted in a 3% decrease in refinery production levels from continuing operations for the three months ended September 30, 2007 as compared to the same period in 2006.

Sales and Other Revenues

Sales and other revenues from continuing operations increased 3% from $1,172.7 million for the third quarter of 2006 to $1,208.7 million for the third quarter of 2007, due principally to higher refined product sales prices. The average sales price we received per produced barrel sold increased 3% from $86.96 for the third quarter of 2006 to $89.56 for the third quarter of 2007. The total volume of produced refined products sold was relatively flat for the third quarter of 2007 as compared to the third quarter of 2006.

Cost of Products Sold

Cost of products sold increased 8% from $979.3 million for the third quarter of 2006 to $1,059.5 million for the third quarter of 2007, due principally to a per unit increase in the cost of produced refined products sold. The total volume of produced refined products sold for the third quarter of 2007 was relatively flat as compared to the third quarter of 2006. The average price we paid per barrel of crude oil and feedstocks purchased and the transportation costs of moving the finished products to the market place increased 11% from $69.21 for the third quarter of 2006 to $76.72 for the third quarter of 2007.

Gross Refinery Margins

Gross refining margin per produced barrel decreased 28% from $17.75 for the third quarter of 2006 to $12.84 for the third quarter of 2007 due to the combined effects of an increase in the average price we paid per barrel of crude oil and feedstocks purchased and an increase in the average sales price we received per produced barrel sold. Gross refinery margin does not include the effects of depreciation, depletion and amortization. See Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 3 of Part 1 of this Form 10-Q for a reconciliation to the income statement of prices of refined products sold and cost of products purchased.

Operating Expenses

Operating expenses, exclusive of depreciation, depletion and amortization, decreased 4% from $54.1 million for the third quarter of 2006 to $52.2 million for the third quarter of 2007, due principally to lower utility costs.

General and Administrative Expenses

General and administrative expenses increased 50% from $12.6 million for the third quarter of 2006 to $18.8 million for the third quarter of 2007, due principally to increased equity-based incentive compensation expense and software implementation costs. The increase in our equity-based compensation expense was due to an increase in our stock price and the accelerated vesting of certain outstanding restricted stock awards.

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Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization increased 11% from $9.5 million for the third quarter of 2006 to $10.5 million for the third quarter of 2007 due to capitalized refinery improvement projects in 2006.

Equity in Earnings of HEP

Our equity in earnings of HEP was $5.6 million for the third quarter of 2007 as compared to $3.6 million for the third quarter of 2006. The increase in our equity in earnings of HEP was due principally to an increase in HEP s earnings in the third quarter of 2007 as compared to the third quarter of 2006.

Interest Income

Interest income for the third quarter of 2007 was $4.4 million as compared to $2.7 million for the third quarter of 2006. The increase in interest income was due principally to the effects of a higher interest rate environment combined with increased investments in marketable debt securities.

Interest Expense

Interest expense was $0.3 million for the third quarter of 2007 and 2006.

Income Taxes

Income taxes decreased 57% from $44.0 million for the third quarter of 2006 to $19.1 million for the third quarter of 2007, due to lower pre-tax earnings during the 2007 third quarter as compared to the 2006 third quarter. The effective tax rate for the third quarter of 2007 was 24.8%, as compared to 35.7% for the third quarter of 2006. The decrease in our effective tax rate was due principally to a statutory increase in the federal tax deduction for domestic manufacturing activities, an increase in the amount of the low sulfur diesel fuel production tax credit and the effects of a higher estimated effective tax rate during the first half of 2007 as compared to the nine months ended September 30, 2007.

Discontinued Operations

We had no income from discontinued operations for the third quarter of 2007 as our Montana Refinery operations have ceased. We realized a loss of $0.2 million from discontinued operations for the third quarter of 2006, which was largely due to the wind down of operations resulting from the sale of our Montana Refinery on March 31, 2006.

Results of Operations Nine Months Ended September 30, 2007 Compared to Nine Months Ended September 30, 2006

Summary

Income from continuing operations was $284.3 million ($5.17 per basic and $5.08 per diluted share) for the nine months ended September 30, 2007, compared to income from continuing operations of $198.1 million ($3.45 per basic and $3.38 per diluted share) for the nine months ended September 30, 2006. Income from continuing operations increased $86.2 million for the nine months ended September 30, 2007, an increase of 44%, as compared to the nine months ended September 30, 2006, principally due to improved refined product margins experienced in the current year and an increase in volume of produced refined products sold. These favorable factors were partially offset by the effects of higher depreciation, depletion and amortization costs and general and administrative expenses incurred in the current year. Overall sales of produced refined products from continuing operations increased by 11% for the nine months ended September 30, 2007 as compared to the same period in 2006 due to an increase in refinery production during the nine months ended September 30, 2007. Overall refinery gross margins from continuing operations were $19.32 per produced barrel for the nine months ended September 30, 2007 compared to refinery gross margins from continuing operations of $17.23 per produced barrel for the nine months ended September 30, 2006.

The large increase in volume of produced refined products sold for the nine months ended September 30, 2007, as compared to the same period in 2006 is attributable to increased production levels during the current year. Our production levels were lower for the nine months ended September 30, 2006 due to planned downtime at our Navajo and Woods Cross Refineries during the second quarter of 2006. To meet this requirement, we completed certain ULSD projects at both refineries during the second quarter of 2006. In conjunction with these ULSD projects, we timed other refinery maintenance projects and an expansion at our Navajo Refinery. Downtime incurred from these capital projects was the principal factor in our reduced production levels during the nine-months ended September 30, 2006. Also

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contributing to our production increase for the nine months ended September 30, 2007 is an increase in production levels at our Navajo Refinery following an 8,000 BPSD refinery expansion in mid-year 2006 combined with an additional 2,000 BPSD expansion in mid-year 2007. This increase was partially offset by a decrease in production during the third quarter of 2007 due to unplanned downtime at our Navajo and Woods Cross Refineries. For the nine months ended September 30, 2007, refinery production from continuing operations increased by 10%, as compared to the same period in 2006.

Sales and Other Revenues

Sales and other revenues from continuing operations increased 9% from $3,085.1 million for the nine months ended September 30, 2006 to $3,351.5 million for the nine months ended September 30, 2007, due principally to higher refined product sales prices and an increase in volumes of produced refined products sold. The average sales price we received per produced barrel sold increased 3% from $83.74 for the nine months ended September 30, 2006 to $86.07 for the nine months ended September 30, 2007. The total volume of produced refined products sold increased by 11% for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006.

Cost of Products Sold

Cost of products sold increased 6% from $2,562.8 million for the nine months ended September 30, 2006 to $2,708.4 million for the nine months ended September 30, 2007, due principally to an increase in volumes of produced refined products sold. The average price we paid per barrel of crude oil and feedstocks purchased and the transportation costs of moving the finished products to the market place increased slightly from $66.51 for the nine months ended September 30, 2006 to $66.75 for the nine months ended September 30, 2007.

Gross Refinery Margins

Gross refining margin per produced barrel increased 12% from $17.23 for the nine months ended September 30, 2006 to $19.32 for the nine months ended September 30, 2007 due to an increase in the average sales price we received per produced barrel sold. Gross refinery margin does not include the effects of depreciation, depletion and amortization. See Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles following Item 3 of Part 1 of this Form 10-Q for a reconciliation to the income statement of prices of refined products sold and cost of products purchased.

Operating Expenses

Operating expenses, exclusive of depreciation, depletion and amortization decreased 2% from $155.7 million for the nine months ended September 30, 2006 to $153.4 million for the nine months ended September 30, 2007, due principally to lower utility costs.

General and Administrative Expenses

General and administrative expenses increased 25% from $44.8 million for the nine months ended September 30, 2006 to $56.0 million for the nine months ended September 30, 2007, due principally to increased equity-based incentive compensation expense and software implementation costs. The increase in our equity-based compensation expense was due to an increase in our stock price and the accelerated vesting of certain outstanding restricted stock awards.

Depreciation, Depletion and Amortization Expenses

Depreciation, depletion and amortization increased 16% from $28.2 million for the nine months ended September 30, 2006 to $32.6 million for the nine months ended September 30, 2007 due to capitalized refinery improvement projects in 2006.

Equity in Earnings of HEP

Our equity in earnings of HEP was $13.9 million for the nine months ended September 30, 2007 as compared to $8.3 million for the nine months ended September 30, 2006. The increase in our equity in earnings of HEP was due principally to an increase in HEP s earnings for the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006.

Interest Income

Interest income for the nine months ended September 30, 2007 was $10.5 million compared to $6.9 million for the nine months ended September 30, 2006. The increase in interest income was due principally to the effects of a higher interest rate environment combined with increased investments in marketable debt securities.

Interest Expense

Interest expense was $0.8 million for the nine months ended September 30, 2007 and 2006.

Income Taxes

Income taxes increased 28% from $109.6 million for the nine months ended September 30, 2006 to $140.0 million for the nine months ended September 30, 2007 due to higher pre-tax earnings during the nine months ended September 30, 2007 as compared to the nine months ended September 30, 2006. The effective tax rate for the nine months ended September 30, 2007 was 33.0%, as compared to 35.6% for the nine months ended September 30, 2006. The decrease in our effective tax rate was due principally to a statutory increase in the federal tax deduction for domestic manufacturing activities and an increase in the amount of the low sulfur diesel fuel production tax credit. The low sulfur diesel production tax credit became effective June 1, 2006 and was available to us for the entire nine months ended September 30, 2007 as compared four months of the nine months ended September 30, 2006.

Discontinued Operations

We had no income from discontinued operations for the nine months ended September 30, 2007 as our Montana Refinery operations have ceased. Income from discontinued operations was $20.8 million for the nine months ended September 30, 2006 which consisted of a $13.8 million gain on the sale of the Montana Refinery, net of $8.2 million in income taxes, and $7.0 million of earnings which was largely due to the liquidation of certain retained quantities of inventories that were not included in the sale of our Montana Refinery on March 31, 2006.

LIQUIDITY AND CAPITAL RESOURCES

We consider all highly-liquid instruments with a maturity of three months or less at the time of purchase to be cash equivalents. Cash equivalents are stated at cost, which approximates market value, and are invested primarily in conservative, highly-rated instruments issued by financial institutions or government entities with strong credit standings. We also invest available cash in highly-rated marketable debt securities primarily issued by government entities that have maturities greater than three months. These securities include investments in variable rate demand notes (VRDN) and auction rate securities (ARS). Although VRDN and ARS may have long-term stated maturities, generally 15 to 30 years, we have designated these securities as available-for-sale and have classified them as current because we view them as available to support our current operations. Rates on VRDN are typically reset either daily or weekly. Rates on ARS are reset through a Dutch auction process at intervals between 35 and 90 days, depending on the terms of the security. VRDN and ARS may be liquidated at par on the rate reset date. We also invest in other marketable debt securities with the maximum maturity of any individual issue not greater than two years from the date of purchase. All of these instruments are classified as available-for-sale, and as a result, are reported at fair value. Unrealized gains and losses, net of related income taxes, are reported as a component of accumulated other comprehensive income or loss. As of September 30, 2007, we had cash and cash equivalents of $39.0 million, marketable securities with maturities under one year of $184.8 million and marketable securities with maturities greater than one year, but less than two years, of $85.9 million.

Cash and cash equivalents decreased by $115.1 million during the nine months ended September 30, 2007. The combined cash used for investing activities of $280.6 million and for financing activities of $91.2 million exceeded cash provided by operating activities of $256.7 million. Working capital increased during the nine months ended September 30, 2007 by $39.0 million.

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We have a $175.0 million secured revolving credit facility with Bank of America as administrative agent and a lender, with a term of four years through July 2008 and an option to increase the facility to $225.0 million subject to certain conditions. The credit facility may be used to fund working capital requirements, capital expenditures, acquisitions and other general corporate purposes. As of September 30, 2007, we had letters of credit outstanding under our revolving credit facility of $2.5 million and had no borrowings outstanding. We were in compliance with all covenants at September 30, 2007.

On August 9, 2007, we announced that our Board of Directors had authorized a $100.0 million increase to our current common stock repurchase program increasing the authorized stock repurchase limit from $300.0 million to $400.0 million. Common stock repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. During the nine months ended September 30, 2007, we repurchased under this repurchase initiative 1,327,090 shares at a cost of $79.0 million or an average of $59.55 per share. Since inception of this repurchase initiative in November 2005 through September 30, 2007, we have repurchased 6,773,297 shares at a cost of $286.0 million or an average of $42.22 per share.

We believe our current cash, cash equivalents and marketable securities, along with future internally generated cash flow and funds available under our credit facility provide sufficient resources to fund currently planned capital projects and our liquidity needs for the foreseeable future as well as allow us to continue payment of quarterly dividends and the repurchase of additional common stock under our common stock repurchase program. In addition, components of our growth strategy may include construction of new refinery processing units and the expansion of existing units at our facilities and selective acquisition of complementary assets for our refining operations intended to increase earnings and cash flow. Our ability to acquire complementary assets will be dependent upon several factors, including our ability to identify attractive acquisition candidates, consummate acquisitions on favorable terms, successfully integrate acquired assets and obtain financing to fund acquisitions and to support our growth, and many other factors beyond our control.

Cash Flows Operating Activities

Net cash flows provided by operating activities were $256.7 million for the nine months ended September 30, 2007 compared to $208.3 million for the nine months ended September 30, 2006, an increase of $48.4 million. Net income for the nine months ended September 30, 2007 was $284.3 million, an increase of $65.4 million from net income of $218.9 million for the nine months ended September 30, 2006. Additionally, the non-cash adjustments to net income of depreciation and amortization, deferred taxes, equity-based compensation and gain on sale of assets resulted in an increase to operating cash flows of $52.4 million for the nine months ended September 30, 2007 as compared to $16.0 million for the nine months ended September 30, 2006. Distributions in excess of equity in earnings of HEP for the nine months ended September 30, 2007 decreased to $3.0 million as compared to $6.7 million for the nine months ended September 30, 2006. Changes in working capital items decreased cash flows by $68.6 million for the nine months ended September 30, 2007, as compared to a decrease of $19.6 million for the nine months ended September 30, 2006, resulting mainly from an increase in inventories and accounts receivable, partially offset by an increase in accounts payable during the first nine months of 2007. For the first nine months of 2007, inventories increased by $50.1 million, as compared to an increase of $8.4 million for the first nine months of 2006. Also for the first nine months of 2007, accounts receivable increased by $184.9 million, as compared to a decrease of $13.5 million for the first nine months of 2006 and accounts payable increased by $171.8 million, as compared to a decrease of $17.3 million for the first nine months of 2006. Additionally, for the first nine months of 2007, there were no turnaround expenditures, as opposed to $7.1 million for the first nine months of 2006.

Cash Flows Investing Activities and Capital Projects

Net cash flows used for investing activities were $280.6 million for the nine months ended September 30, 2007, as compared to net cash flows provided by investing activities of $73.3 million for the nine months ended September 30, 2006, a net change of $353.9 million. Cash expenditures for property, plant and equipment for the first nine months of 2007 totaled $113.2 million as compared to $89.2 million for the same period in 2006. On March 31, 2006 we sold our Montana Refinery to Connacher. The cash proceeds we received on the sale of the Montana Refinery were

$48.9 million, net of transaction fees and expenses. We also invested $561.8 million in marketable securities and received proceeds of $394.4 million from the sale or maturity of marketable securities during the nine months ended September 30, 2007. For the nine months ended September 30, 2006, we invested $172.3 million in marketable securities and received proceeds of $285.9 million from the sale or maturity of marketable securities.

Planned Capital Expenditures

Each year our Board of Directors approves in our annual capital budget capital projects that our management is authorized to undertake. Additionally, at times when conditions warrant or as new opportunities arise, other special projects may be approved. The funds allocated for a particular capital project may be expended over a period of several years, depending on the time required to complete the project. Therefore, our planned capital expenditures for a given year consist of expenditures approved for capital projects included in the current year s capital budget as well as, in certain cases, expenditures approved for capital projects in capital budgets for prior years. Our total capital budget for 2007 is approximately $42.1 million, not including the capital projects approved in prior years and our expansion and feedstock flexibility projects at the Navajo and Woods Cross refineries and pipeline projects as described below. The 2007 capital budget is comprised of $24.7 million for refining improvement projects for the Navajo Refinery, $9.7 million for projects at the Woods Cross Refinery, $3.2 million for transportation projects, $0.5 million for marketing-related projects, $2.8 million for asphalt plant projects and $1.2 million for information technology and other miscellaneous projects.

At the Navajo Refinery, we will be installing an additional 100 ton per day sulfur recovery unit at an estimated cost of $26.0 million that will permit Navajo to process 100% sour crude. The sulfur recovery unit is planned for start-up in the first quarter of 2009. Also, we will be installing a new 15,000 BPSD hydrocracker and a new 28 MMSCFSD hydrogen plant at a budgeted cost of $134.0 million. The addition of these units is expected to increase liquid volume recovery, increase the refinery s capacity to process outside feedstocks, increase yields of high-valued products and enable the refinery to meet the EPA s new low sulfur gasoline specifications. Engineering / procurement of this project is approximately 60% complete. Construction is currently awaiting approval of environmental permits in the state of New Mexico.

As announced in February 2007, we will be revamping the Lovington crude unit at the Navajo Refinery which will increase crude capacity to approximately 100,000 BPSD. In addition, our Board of Directors has approved a revamp of the Artesia crude unit and the installation of a new 20,000 BPSD ROSE unit, which combined with the hydrogen plant and the new hydrocracker and sulfur recovery units, will allow the Navajo Refinery to process approximately 40,000 BPSD of heavy Canadian crude oil. The estimated cost of the combined crude expansion and heavy Canadian crude oil processing project is $240.0 million. It is currently anticipated that the expansion portion of the overall project consisting of the initial crude unit revamp, the new hydrocracker and the new hydrogen plant will be completed in the first quarter of 2009. The completion of the heavy crude oil processing portion of the overall project, including the second crude unit revamp and the installation of the new solvent de-asphalter, will be targeted to coincide with development of future pipeline access to the Navajo Refinery for heavy Canadian crude oil and other foreign heavy crude oils transported from the Cushing, Oklahoma area. We plan to explore with HEP the most economical manner to obtain this needed pipeline access.

At the Woods Cross Refinery, we will be adding a new 15,000 BPSD hydrocracker along with sulfur recovery and desalting equipment. The budgeted cost of these additions is approximately $100.0 million. These additions will expand the Woods Cross Refinery s crude processing capabilities from 26,000 BPSD to 31,000 BPSD while enabling the refinery to process up to 10,000 BPSD of high-value low-priced black wax crude oil and up to 5,000 BPSD of low-priced heavy Canadian crude oils. The Woods Cross Refinery expansion project as approved involves a higher capital investment than had originally been estimated, principally because of the substitution of a complex hydrocracker in place of certain desulfurization and expanded bottoms-processing modifications that had been included in preliminary planning. The substitution of the complex hydrocracker is expected to provide increased capabilities to process significantly more black wax crude oils, which have recently been priced at substantial discounts to West Texas Intermediate crude oil, while yielding substantially higher value products than the discounted heavy Canadian crudes that were a more significant part of the original plan. These additions would also increase the refinery s capacity to process low-cost feedstocks and provide the necessary infrastructure for future

expansions of crude oil refining capacity at the Woods Cross Refinery while enabling the refinery to meet the EPA s new low sulfur gasoline specifications. Hydrogen for this project will be supplied by a third party supplier under a contract for the next 15 years. The approved projects for the Woods Cross Refinery are expected to be completed during the third quarter of 2008.

In 2007, we expect to expend an estimated total of $179.0 million on currently approved refinery capital projects, which amount consists of certain carryovers of capital projects from previous years, less carryovers to subsequent years of certain of the currently approved capital projects.

To fully take advantage of the economics on the Woods Cross expansion project, additional crude pipeline capacity will be required to move Canadian crude to the Woods Cross Refinery. In February 2007, HEP entered into a letter of intent with Plains All American Pipeline, L.P. (Plains) under which HEP will own a 25% interest in a new 95 mile intrastate pipeline system, now being constructed by Plains, capable of shipping up to 120,000 BPD of crude oil into the Salt Lake City area.

As previously announced, we have entered into a Memorandum of Understanding with Sinclair Transportation Company (Sinclair) to jointly build a 12-inch pipeline from Salt Lake City, Utah to Las Vegas, Nevada, together with terminal facilities in the Cedar City, Utah and north Las Vegas areas (the UNEV Pipeline). Subject to the execution of definitive agreements, we will own a 75% interest and Sinclair will own a 25% interest in the project. We have an understanding with HEP that they will be the operator and will have an option to purchase our interest in the project, effective for a 180-day period commencing when the UNEV Pipeline becomes operational, at a purchase price equal to our share of actual costs, plus interest at 7% per annum. The initial capacity of the pipeline will be 62,000 BPD, with the capacity for further expansion to 120,000 BPD. The cost of the pipeline is expected to be $225.0 million, and the total cost of the project including terminals is expected to be approximately $300.0 million. Construction of this project is currently expected to be completed and operational in early 2009.

In October 2004, the American Jobs Creation Act of 2004 (2004 Act) was signed into law. Among other things, the 2004 Act created tax incentives for small business refiners incurring costs to produce ULSD. The 2004 Act provided an immediate deduction of 75% of certain costs paid or incurred to comply with the ULSD standards, and a tax credit based on ULSD production of up to 25% of those costs. We estimate the tax savings that we derive from planned capital expenditures associated with the 2004 Act will result in a reduction in our income tax expense of $15.6 million in 2007, representing the difference between the value of allowed credits under the 2004 Act as compared to the value of depreciating the investments. In August 2005, the Energy Policy Act of 2005 (2005 Act) was signed into law. Among other things, the 2005 Act created tax incentives for refiners by providing for an immediate deduction of 50% of certain refinery capacity expansion costs when the expansion assets are placed in service. We believe the capacity expansion projects at the Navajo and Woods Cross Refineries will qualify for this deduction.

The above mentioned regulatory compliance items, including the ULSD and LSG requirements, or other presently existing or future environmental regulations could cause us to make additional capital investments beyond those described above and incur additional operating costs to meet applicable requirements.

Cash Flows Financing Activities

Net cash flows used for financing activities were $91.2 million for the nine months ended September 30, 2007, as compared to $136.0 million for the nine months ended September 30, 2006, a decrease of $44.8 million. Under our common stock repurchase program, we purchased treasury stock of $79.0 million during the nine months ended September 30, 2007 and $137.0 million during the nine months ended September 30, 2006. Our treasury stock purchases for the nine months ended September 30, 2007 and 2006, include $5.1 million and $1.4 million, respectively, in common stock purchased from certain officers and other key employees, at market prices, made under the terms of restricted stock agreements to provide funds for the payment of payroll and income taxes due at the vesting of restricted shares in the case of executives who did not elect to satisfy such taxes by other means. During the nine months ended September 30, 2007, we paid $16.7 million in dividends, received $0.6 million for common stock issued upon exercise of stock options, and recognized $8.9 million in excess tax benefits on our equity based compensation. During the nine months ended September 30, 2006, we paid $10.5 million in dividends, received $2.4 million for common stock issued upon exercise of stock options and recognized $10.4 million in excess tax benefits on our equity based compensation.

Contractual Obligations and Commitments

HEP serves our refineries in New Mexico and Utah under a 15-year pipelines and terminals agreement (HEP PTA) expiring in 2019 and a 15-year intermediate pipeline agreement expiring in 2020 (HEP IPA). Under the HEP PTA, we pay HEP fees to transport on HEP s refined product pipelines or throughput in HEP s terminals a volume of refined products that will result in minimum annual payments to HEP. Following the July 1, 2007 producer price index (PPI) rate adjustment, minimum payments under the HEP PTA will be $39.6 million for the twelve months ending June 30, 2008. Under the HEP IPA, we agreed to transport volumes of intermediate products on the intermediate pipelines that will result in minimum annual payments to HEP. Following the July 1, 2007 PPI rate adjustment, minimum payments under the HEP IPA will be $12.8 million for the twelve months ending June 30, 2008. Minimum revenues for both agreements will adjust upward based on increases in the producer price index over the term of the agreements. Additionally, we agreed to indemnify HEP up to an aggregate amount of $17.5 million for any environmental noncompliance and remediation liabilities associated with the assets transferred to HEP and occurring or existing prior to the date of the transfers of ownership to HEP. Of this total, indemnification in excess of $15.0 million relates solely to the intermediate pipelines.

On October 15, 2007, we entered into an agreement with HEP that amends the HEP PTA under which HEP has agreed to expand their refined products pipeline system between Artesia, New Mexico and El Paso, Texas (the South System). The amendment also provides for a tariff increase, effective May 1, 2008, on our shipments on HEP s refined product pipelines and monetary incentives to HEP for the early completion of the South System expansion, currently targeted for January 31, 2009.

HEP financed the Alon transaction through a private offering of $150.0 million principal amount of HEP Senior Notes. HEP increased these notes to $185.0 million as part of the purchase of our intermediate pipelines. The $185.0 million HEP Senior Notes are not recorded on our accompanying consolidated balance sheets at September 30, 2007 or December 31, 2006. Navajo Pipeline Co., L.P., one of our subsidiaries, has agreed to indemnify HEP s general partner to the extent it makes any payment in satisfaction of $35.0 million of the principal amount of the HEP Senior Notes.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have Federal Clean Air Act liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo and Montana refineries. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refinery. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement. With respect to the 2001 Consent Agreement we entered into for our Navajo and Montana refineries, following the sale of the Montana Refinery in March 2006 our remaining commitment relates to the Navajo Refinery and, with the investments made to date, our outstanding required investments are no longer significant.

CRITICAL ACCOUNTING POLICIES

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the

United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from these estimates under different assumptions or conditions.

Our significant accounting policies are described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies in our Annual Report on Form 10-K for the year ended December 31, 2006. Certain critical accounting policies that materially affect the amounts recorded in our consolidated financial statements are the use of the LIFO method of valuing certain inventories, the amortization of deferred costs for regular major maintenance and repairs at our refineries, assessing the possible impairment of certain long-lived assets, and assessing contingent liabilities for probable losses. There have been no changes to these policies in 2007.

We use the last-in, first-out (LIFO) method of valuing inventory. Under the LIFO method, an actual valuation of inventory can only be made at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management s estimates of expected year-end inventory levels and are subject to the final year-end LIFO inventory valuation.

New Accounting Pronouncements

EITF No.06-11 Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards

In June 2007, the FASB ratified Emerging Issues Task Force (EITF) No. 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF No. 06-11 requires that tax benefits generated by dividends paid during the vesting period on certain equity-classified share-based compensation awards be classified as additional paid-in capital and included in a pool of excess tax benefits available to absorb tax deficiencies from share-based payment awards. EITF No. 06-11 is effective for fiscal years beginning after December 15, 2007. While we are currently evaluating the impact of EITF No. 06-11, we do not expect the adoption of this standard to have a material impact on our financial condition, results of operations and cash flows.

SFAS No. 159 The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No 115. SFAS No. 159, which amends SFAS No. 115, allows certain financial assets and liabilities to be recognized, at a company s election, at fair market value, with any gains or losses for the period recorded in the statement of income. SFAS No. 159 includes available-for-sale securities in the assets eligible for this treatment. Currently, we record the gains or losses for the period as a component of comprehensive income and in the equity section of the balance sheet. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, and interim periods in those fiscal years. We do not expect the adoption of this statement to have a material impact on our financial condition, results of operations and cash flows.

Interpretation No. 48 Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes. This interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. We adopted this standard effective January 1, 2007. As a result of the implementation of this standard, we recognized no material adjustment in the liability for unrecognized income tax benefits.

We are subject to U.S. federal income tax and to the income tax of multiple state jurisdictions. We have substantially concluded all U.S. federal, state and local income tax matters for fiscal years through July 31, 2002. In 2006, the Internal Revenue Service commenced examinations of our U.S. federal income tax returns for the tax years ended July 31, 2003 and December 31, 2003. To date, we do not anticipate that the resolution of this audit will result in a material change to our financial condition, results of operations or cash flows.

Our policy is to recognize potential interest and penalties related to income tax matters in income tax expense. We believe we have appropriate support for the income tax positions taken and to be taken on our income tax returns and that our accruals for tax liabilities are adequate for all open years based on an assessment of many factors, including past experience and interpretations of tax law applied to the facts of each matter.

SFAS No. 157 Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This standard simplifies and codifies guidance on fair value measurements under generally accepted accounting principles. This standard defines fair value, establishes a framework for measuring fair value and prescribes expanded disclosures about fair value measurements. This standard is effective for fiscal years beginning after November 15, 2007. We do not anticipate that the adoption of this interpretation will have a material effect on our financial condition, results of operations and cash flows.

RISK MANAGEMENT

We use certain strategies to reduce some commodity price and operational risks. We do not attempt to eliminate all market risk exposures when we believe that the exposure relating to such risk would not be significant to our future earnings, financial position, capital resources or liquidity or that the cost of eliminating the exposure would outweigh the benefit. Our profitability depends largely on the spread between market prices for refined products and market prices for crude oil. A substantial or prolonged reduction in this spread could have a significant negative effect on our earnings, financial condition and cash flows.

We periodically utilize petroleum commodity futures contracts to reduce our exposure to price fluctuations associated with crude oil and refined products. Such contracts historically have been used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. We have also utilized commodity price swaps and collar options to help manage the exposure to price volatility relating to forecasted purchases of natural gas. We have not had any open positions since 2005.

We regularly utilize contracts that provide for the purchase of crude oil and other feedstocks and for the sale of refined products. Certain of these contracts may meet the definition of a derivative instrument in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. We believe these contracts qualify for the normal purchases and normal sales exception under SFAS No. 133, because deliveries under the contracts will be in quantities expected to be used or sold over a reasonable period of time in the normal course of business. Accordingly, these contracts are designated as normal purchases and normal sales contracts and are not required to be recorded as derivative instruments under SFAS No. 133.

At September 30, 2007, we had no outstanding debt. As the interest rates on our bank borrowings are reset frequently based on either the bank s daily effective base rate or the London Interbank Offered Rate (LIBOR) rate, interest rate market risk on any bank borrowings would be very low. At times, we have used borrowings under our credit facility to finance our working capital needs. There were no borrowings under the credit facilities as of September 30, 2007.

We invest a substantial portion of available cash in investment grade, highly liquid investments with maturities of three months or less and hence the interest rate market risk implicit in these cash investments is low. We also invest the remainder of available cash in portfolios of highly rated marketable debt securities, primarily issued by government entities, that have an average remaining duration (including any cash equivalents invested) of not greater than one year and hence the interest rate market risk implicit in these investments is also low. A hypothetical 10% change in the market interest rate over the next year would not materially impact our earnings, cash flow or financial condition since any borrowings under the credit facilities and our investments are at market rates

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and interest on borrowings and cash investments has historically not been significant as compared to our total operations.

Our operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. We maintain various insurance coverages, including business interruption insurance, subject to certain deductibles. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

See Risk Management under Management s Discussion and Analysis of Financial Condition and Results of Operations.

Reconciliations to Amounts Reported Under Generally Accepted Accounting Principles

Reconciliations of earnings before interest, taxes, depreciation and amortization (EBITDA) to amounts reported under generally accepted accounting principles in financial statements.

Earnings before interest, taxes, depreciation and amortization, which we refer to as EBITDA, is calculated as net income plus (i) interest expense net of interest income, (ii) income tax provision, and (iii) depreciation, depletion and amortization. EBITDA is not a calculation provided for under accounting principles generally accepted in the United States; however, the amounts included in the EBITDA calculation are derived from amounts included in our consolidated financial statements. EBITDA should not be considered as an alternative to net income or operating income as an indication of our operating performance or as an alternative to operating cash flow as a measure of liquidity. EBITDA is not necessarily comparable to similarly titled measures of other companies. EBITDA is presented here because it is a widely used financial indicator used by investors and analysts to measure performance. EBITDA is also used by our management for internal analysis and as a basis for financial covenants. We are reporting EBITDA from continuing operations.

Set forth below is our calculation of EBITDA from continuing operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(In thousands)			
Income from continuing operations	$ 58,126	$ 79,201	$ 284,295	$ 198,090
Add provision for income tax	19,141	43,964	139,963	109,599
Add interest expense	297	268	840	815
Subtract interest income	(4,368)	(2,747)	(10,478)	(6,890)
Add depreciation, depletion and amortization	10,531	9,480	32,623	28,187
EBITDA from continuing operations	$ 83,727	$ 130,166	$ 447,243	$ 329,801

Reconciliations of refinery operating information (non-GAAP performance measures) to amounts reported under generally accepted accounting principles in financial statements.

Refinery gross margin and net operating margin are non-GAAP performance measures that are used by our management and others to compare our refining performance to that of other companies in our industry. We believe these margin measures are helpful to investors in evaluating our refining performance on a relative and absolute basis. We calculate refinery gross margin and net operating margin using net sales, cost of products and operating expenses, in each case averaged per produced barrel sold. These two margins do not include the effect of depreciation, depletion and amortization. Each of these component performance measures can be reconciled directly to our Consolidated Statements of Income.

Other companies in our industry may not calculate these performance measures in the same manner.

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Refinery Gross Margin

Refinery gross margin per barrel is the difference between average net sales price and average cost of products per barrel of produced refined products. Refinery gross margin for each of our refineries and for both of our refineries on a consolidated basis is calculated as shown below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Average per produced barrel:				
Navajo Refinery				
Net sales	$ 88.46	$ 84.49	$ 85.88	$ 83.21
Less cost of products	77.80	68.40	67.32	66.16
Refinery gross margin	$ 10.66	$ 16.09	$ 18.56	$ 17.05
Woods Cross Refinery				
Net sales	$ 93.06	$ 94.88	$ 86.69	$ 85.33
Less cost of products	73.27	71.82	64.91	67.56
Refinery gross margin	$ 19.79	$ 23.06	$ 21.78	$ 17.77
Consolidated				
Net sales	$ 89.56	$ 86.96	$ 86.07	$ 83.74
Less cost of products	76.72	69.21	66.75	66.51
Refinery gross margin	$ 12.84	$ 17.75	$ 19.32	$ 17.23

Net Operating Margin

Net operating margin per barrel is the difference between refinery gross margin and refinery operating expenses per barrel of produced refined products. Net operating margin for each of our refineries and for all of our refineries on a consolidated basis is calculated as shown below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Average per produced barrel:				
Navajo Refinery				
Refinery gross margin	$ 10.66	$ 16.09	$ 18.56	$ 17.05
Less refinery operating expenses	4.69	4.89	4.37	5.00
Net operating margin	$ 5.97	$ 11.20	$ 14.19	$ 12.05
Woods Cross Refinery				
Refinery gross margin	$ 19.79	$ 23.06	$ 21.78	$ 17.77

Less refinery operating expenses	5.01	5.18	4.66	5.01
Net operating margin	$ 14.78	$ 17.88	$ 17.12	$ 12.76
Consolidated				
Refinery gross margin	$ 12.84	$ 17.75	$ 19.32	$ 17.23
Less refinery operating expenses	4.77	4.96	4.44	5.00
Net operating margin	$ 8.07	$ 12.79	$ 14.88	$ 12.23

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Below are reconciliations to our Consolidated Statements of Income for (i) net sales, cost of products and operating expenses, in each case averaged per produced barrel sold, and (ii) net operating margin and refinery gross margin. Due to rounding of reported numbers, some amounts may not calculate exactly.

Reconciliations of refined product sales from produced products sold to total sales and other revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Navajo Refinery				
Average sales price per produced barrel sold	$ 88.46	$ 84.49	$ 85.88	$ 83.21
Times sales of produced refined products sold (BPD)	80,500	80,950	85,500	75,680
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 655,135	$ 629,231	$ 2,004,568	$ 1,719,172
Woods Cross Refinery				
Average sales price per produced barrel sold	$ 93.06	$ 94.88	$ 86.69	$ 85.33
Times sales of produced refined products sold (BPD)	25,250	25,160	26,490	25,320
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 216,178	$ 219,621	$ 626,922	$ 589,832
Sum of refined product sales from produced products sold from our two refineries (4)	$ 871,313	$ 848,852	$ 2,631,490	$ 2,309,004
Add refined product sales from purchased products and rounding (1)	150,574	143,421	321,443	395,664
Total refined product sales	1,021,887	992,273	2,952,933	2,704,668
Add direct sales of excess crude oil(2)	143,277	143,103	296,800	274,378
Add other refining segment revenue(3)	43,081	37,033	100,871	105,549
Total refining segment revenue	1,208,245	1,172,409	3,350,604	3,084,595
Add corporate and other revenues	426	404	931	928
Add (subtract) consolidations and eliminations		(120)		(396)
Sales and other revenues	$ 1,208,671	$ 1,172,693	$ 3,351,535	$ 3,085,127

(1) We purchase finished products when opportunities arise that

provide a profit on the sale of such products, or to meet delivery commitments.

(2) We purchase crude oil and enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.

(3) Other refining segment revenue

includes the revenues associated with Holly Asphalt and revenue derived from feedstock and sulfur credit sales.

(4) *The above calculations of refined product sales from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Average sales price per produced barrel sold	$ 89.56	$ 86.96	$ 86.07	$ 83.74
Times sales of produced refined products sold (BPD)	105,750	106,110	111,990	101,000
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 871,313	$ 848,852	$ 2,631,490	$ 2,309,004

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Reconciliation of average cost of products per produced barrel sold to total costs of products sold

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Navajo Refinery				
Average cost of products per produced barrel sold	$ 77.80	$ 68.40	$ 67.32	$ 66.16
Times sales of produced refined products sold (BPD)	80,500	80,950	85,500	75,680
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 576,187	$ 509,402	$ 1,571,350	$ 1,366,908
Woods Cross Refinery				
Average cost of products per produced barrel sold	$ 73.27	$ 71.82	$ 64.91	$ 67.56
Times sales of produced refined products sold (BPD)	25,250	25,160	26,490	25,320
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 170,206	$ 166,243	$ 469,414	$ 466,999
Sum of cost of products for produced products sold from our two refineries [4]	$ 746,393	$ 675,645	$ 2,040,764	$ 1,833,907
Add refined product costs from purchased products sold and rounding [1]	149,569	136,241	317,905	394,131
Total refined cost of products sold	895,962	811,886	2,358,669	2,228,038
Add crude oil cost of direct sales of excess crude oil[2]	143,383	142,863	297,289	273,924
Add other refining segment cost of products sold[3]	20,126	24,680	52,464	61,237
Total refining segment cost of products sold	1,059,471	979,429	2,708,422	2,563,199
Add (subtract) consolidations and eliminations		(120)		(396)
Cost of products sold (exclusive of depreciation, depletion and amortization)	$ 1,059,471	$ 979,309	$ 2,708,422	$ 2,562,803

(1) We purchase finished products when opportunities arise that provide a profit on the sale of such products, or to meet

delivery commitments.

(2) *We purchase crude oil and enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.*

(3) *Other refining segment cost of products sold includes the cost of products for Holly Asphalt*

and costs attributable to feedstock and sulfur credit sales.

(4) *The above calculations of refined product sales from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Average cost of products per produced barrel sold	$ 76.72	$ 69.21	$ 66.75	$ 66.51
Times sales of produced refined products sold (BPD)	105,750	106,110	111,990	101,000
Times number of days in period	92	92	273	273
Cost of products for produced products sold	$ 746,393	$ 675,645	$ 2,040,764	$ 1,833,907

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Reconciliation of average refinery operating expenses per produced barrel sold to total operating expenses

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
Navajo Refinery				
Average refinery operating expenses per produced barrel sold	$ 4.69	$ 4.89	$ 4.37	$ 5.00
Times sales of produced refined products sold (BPD)	80,500	80,950	85,500	75,680
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 34,734	$ 36,418	$ 102,002	$ 103,303
Woods Cross Refinery				
Average refinery operating expenses per produced barrel sold	$ 5.01	$ 5.18	$ 4.66	$ 5.01
Times sales of produced refined products sold (BPD)	25,250	25,160	26,490	25,320
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 11,638	$ 11,990	$ 33,700	$ 34,631
Sum of refinery operating expenses per produced products sold from our two refineries [(2)]	$ 46,372	$ 48,408	$ 135,702	$ 137,934
Add other refining segment operating expenses and rounding [(1)]	5,816	5,714	17,717	17,731
Total refining segment operating expenses	52,188	54,122	153,419	155,665
Add corporate and other costs	(3)	24	11	40
Operating expenses (exclusive of depreciation, depletion and amortization)	$ 52,185	$ 54,146	$ 153,430	$ 155,705

(1) Other refining segment operating expenses include the marketing costs associated with our refining segment and the operating expenses of Holly Asphalt.

(2)

The above calculations of refinery operating expenses from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Average refinery operating expenses per produced barrel sold	$ 4.77	$ 4.96	$ 4.44	$ 5.00
Times sales of produced refined products sold (BPD)	105,750	106,110	111,990	101,000
Times number of days in period	92	92	273	273
Refinery operating expenses for produced products sold	$ 46,372	$ 48,408	$ 135,702	$ 137,934

<u>Reconciliation of net operating margin per barrel to refinery gross margin per barrel to total sales and other revenues</u>

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Navajo Refinery				
Net operating margin per barrel	$ 5.97	$ 11.20	$ 14.19	$ 12.05
Add average refinery operating expenses per produced barrel	4.69	4.89	4.37	5.00
Refinery gross margin per barrel	10.66	16.09	18.56	17.05
Add average cost of products per produced barrel sold	77.80	68.40	67.32	66.16
Average sales price per produced barrel sold	$ 88.46	$ 84.49	$ 85.88	$ 83.21
Times sales of produced refined products sold (BPD)	80,500	80,950	85,500	75,680
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 655,135	$ 629,231	$ 2,004,568	$ 1,719,172

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Woods Cross Refinery				
Net operating margin per barrel	$ 14.78	$ 17.88	$ 17.12	$ 12.76
Add average refinery operating expenses per produced barrel	5.01	5.18	4.66	5.01
Refinery gross margin per barrel	19.79	23.06	21.78	17.77
Add average cost of products per produced barrel sold	73.27	71.82	64.91	67.56
Average sales price per produced barrel sold	$ 93.06	$ 94.88	$ 86.69	$ 85.33
Times sales of produced refined products sold (BPD)	25,250	25,160	26,490	25,320
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 216,178	$ 219,621	$ 626,922	$ 589,832
Sum of refined products sales from produced products sold from our two refineries (4)	$ 871,313	$ 848,852	$ 2,631,490	$ 2,309,004
Add refined product sales from purchased products and rounding (1)	150,574	143,421	321,443	395,664
Total refined product sales	1,021,887	992,273	2,952,933	2,704,668
Add direct sales of excess crude oil (2)	143,277	143,103	296,800	274,378
Add other refining segment revenue (3)	43,081	37,033	100,871	105,549
Total refining segment revenue	1,208,245	1,172,409	3,350,604	3,084,595
Add corporate and other revenues	426	404	931	928
Add (subtract) consolidations and eliminations		(120)		(396)
Sales and other revenues	$ 1,208,671	$ 1,172,693	$ 3,351,535	$ 3,085,127

(1) We purchase finished products when opportunities arise that provide a profit on the sale of such products or to meet delivery commitments.

(2) *We purchase crude oil and enter into buy/sell exchanges in excess of the needs to supply our refineries. Certain direct sales of this excess crude oil are made to purchasers or users of crude oil. Under new accounting guidance, these sales and related purchases starting April 1, 2006 are being measured at fair value and accounted for as revenues with the related acquisition costs included as cost of products sold. Prior to April 1, 2006, sales and cost of sales attributable to such excess crude oil direct sales were netted and presented in cost of products sold.*

(3) *Other refining segment revenue includes the revenues associated with Holly Asphalt and revenue derived from*

feedstock and sulfur credit sales.

(4) *The above calculations of refined product sales from produced products sold can also be computed on a consolidated basis. These amounts may not calculate exactly due to rounding of reported numbers.*

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Net operating margin per barrel	$ 8.07	$ 12.79	$ 14.88	$ 12.23
Add average refinery operating expenses per produced barrel	4.77	4.96	4.44	5.00
Refinery gross margin per barrel	12.84	17.75	19.32	17.23
Add average cost of products per produced barrel sold	76.72	69.21	66.75	66.51
Average sales price per produced barrel sold	$ 89.56	$ 86.96	$ 86.07	$ 83.74
Times sales of produced refined products sold (BPD)	105,750	106,110	111,990	101,000
Times number of days in period	92	92	273	273
Refined product sales from produced products sold	$ 871,313	$ 848,852	$ 2,631,490	$ 2,309,004

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Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. Our principal executive officer and principal financial officer have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the Exchange Act), our disclosure controls and procedures (as defined in Exchange Act (ule 13a-15(e)) as of the end of the period covered by this quarterly report on Form 10-Q. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of our disclosure controls and procedures are effective in ensuring that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have been materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

On May 29, 2007, the United States Court of Appeals for the District of Columbia Circuit (Court of Appeals) issued its decision on petitions for review, brought by us and other parties, concerning rulings by the Federal Energy Regulatory Commission (FERC) in proceedings brought by us and other parties against SFPP. These proceedings relate to tariffs of common carrier pipelines, which are owned and operated by SFPP, for shipments of refined products from El Paso, Texas to Tucson and Phoenix, Arizona and from points in California to points in Arizona. We are one of several refiners that regularly utilize an SFPP pipeline to ship refined products from El Paso, Texas to Tucson and Phoenix, Arizona. The Court of Appeals in its May 29, 2007 decision approved a FERC position, which is adverse to us, on the treatment of income taxes in the calculation of allowable rates for pipelines operated by partnerships and ruled in our favor on an issue relating to our rights to reparations when it is determined that certain tariffs we paid to SFPP in the past were too high. We currently estimate that, as a result of this decision and prior rulings by the Court of Appeals and the FERC in these proceedings, a net amount will be due from SFPP to us for the years 1992 through August 31, 2006 in addition to the $15.3 million we received in 2003 from SFPP as reparations for the period from 1992 through July 2000. Because proceedings in the FERC following the Court of Appeals decision have not been completed and because the decision of the Court of Appeals could be the subject of petitions by one or more parties seeking United States Supreme Court review of issues addressed, it is not possible at this time to determine what will be the net amount payable to us at the conclusion of these proceedings. We and other shippers are currently engaged in settlement discussions with SFPP on remaining issues in the FERC proceedings. These discussions have achieved an agreement for partial settlement relating to shipments from El Paso to Tucson and Phoenix for the period from June 1, 2006 through November 30, 2007. If approved by the FERC, the settlement would leave for resolution in pending proceedings all remaining issues for other periods.

We have pending in the United States Court of Federal Claims a lawsuit against the Department of Defense relating to claims totaling approximately $299.0 million with respect to jet fuel sales by two subsidiaries in the years 1982 through 1999. Our claims are similar to claims in a number of other cases that have also been pending in the United States Court of Federal Claims brought by other refining companies concerning military fuel sales. In response to our request, the judge in our case issued in February 2006 an order continuing the stay of our case originally ordered in March 2004. While the stay of our case has been in effect, further judicial proceedings in other cases brought by other refining companies have clarified the legal standards that apply to our case. In August and September 2006, three judges of the United States Court of Federal Claims issued rulings adverse to three other refining companies on issues that are also involved in our case. The refining companies that received these adverse rulings filed appeals of the adverse rulings to the United States Court of Appeals for the Federal Circuit in the fall of 2006, and in September 2007 unfavorable decisions were issued in those appeals. At the date of this report, we expect our case to be settled with a mutual release and do not plan to take any additional action with respect to this lawsuit.

In discussions beginning in the last half of 2005, the EPA and the State of Utah have asserted that we have Federal Clean Air Act liabilities relating to our Woods Cross Refinery because of actions taken or not taken by prior owners of the Woods Cross Refinery, which we purchased from ConocoPhillips in June 2003. We have tentatively agreed with the EPA and the State of Utah to settle the issues presented by means of an agreement similar to the 2001 Consent Agreement we entered into for our Navajo Refinery and previously-owned Montana Refinery. The tentative settlement agreement, which has not yet been put into a final written agreement, includes proposed obligations for us to make specified additional capital investments expected to total up to approximately $10.0 million over several years and to make changes in operating procedures at the refinery. The agreements for the purchase of the Woods Cross Refinery provide that ConocoPhillips will indemnify us, subject to specified limitations, for environmental claims arising from circumstances prior to our purchase of the refinery. We believe that, in the present circumstances, the amount due to us from ConocoPhillips under the agreements for the purchase of the Woods Cross Refinery would be approximately $1.4 million with respect to the tentative settlement.

Our Navajo Refining Company subsidiary is named as a defendant, along with approximately 40 other companies involved in oil refining and marketing and related businesses, in a lawsuit originally filed in May 2006 by the State of

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New Mexico in the U.S. District Court for the District of New Mexico. The lawsuit, as amended in October 2006 through the filing of a second amended complaint in the U.S. District Court for the Southern District of New York under multidistrict procedures, alleges that the defendants are liable for contaminating the waters of New Mexico through producing and/or supplying MTBE or gasoline or other products containing MTBE. The claims made are for defective design or product, failure to warn, negligence, public nuisance, statutory public nuisance, private nuisance, trespass, and civil conspiracy. The second amended complaint also contains a claim, which is asserted in the complaint only against certain other defendants but which appears to be similar to a claim that has been threatened in a mailing to Navajo by law firms representing the plaintiff in this case, alleging violations of certain provisions of the Toxic Substances Control Act. The lawsuit seeks compensatory damages unspecified in amount, injunctive relief, exemplary and punitive damages, costs, attorney s fees allowed by law, and interest allowed by law. As of the close of business on the day prior to the date of this report, Navajo has not been served in this case. At the date of this report, it is not possible to predict the likely course or outcome of this litigation.

On December 6, 2006, the Montana Department of Environmental Quality (MDEQ) filed in state district court in Great Falls, Montana a Complaint and Application for Preliminary Injunction (the Complaint) naming as defendants Montana Refining Company (MRC), our subsidiary that owned the Great Falls, Montana refinery until it was sold to an unrelated purchaser on March 31, 2006, and the unrelated company that purchased the refinery from MRC. The MDEQ asserts in the Complaint that the Great Falls refinery exceeded limitations on sulfur dioxide in the refinery s air emission permit on certain dates in 2004 and 2005 and in 2006 both before and after the sale of the refinery, erroneously certified compliance with limitations on sulfur dioxide emissions, failed to promptly report emissions limit deviations, exceeded limits on sulfur in fuel gas on specified dates in 2005, failed in 2005 to conduct timely testing for certain emissions, submitted late a report required to be submitted in early 2006, failed to achieve a specified limitation on certain emissions in the first three quarters of 2006, and failed to timely submit a report on a 2005 emissions test. The Complaint seeks penalties under applicable law of up to $10,000 per violation and an order enjoining MRC and the current owner of the refinery from further violations. While we do not agree with a number of the violations asserted in the Complaint, we and the current owner of the Great Falls refinery have been in negotiations with the MDEQ both before and after the filing of the Complaint to attempt to settle the issues raised on a compromise basis. At the date of this report, we have negotiated a tentative settlement agreement, which has not yet been put into a final written agreement, under which we would make payments totaling approximately $100,000.

We are a party to various other litigation and proceedings not mentioned in this report which we believe, based on advice of counsel, will not either individually or in the aggregate have a materially adverse impact on our financial condition, results of operations or cash flows.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

(c) ***Common Stock Repurchases Made in the Quarter***

Under our common stock repurchase program (announced in November 2005 and increased from $300 million to $400 million in August 2007), repurchases are being made from time to time in the open market or privately negotiated transactions based on market conditions, securities law limitations and other factors. The following table includes repurchases made under this program during the third quarter of 2007.

Period	Total Number of Shares Purchased	Average price Paid Per Share	Total Number of Shares Purchased as Part of $400 Million Program	Maximum Dollar Value of Shares Yet to be Purchased as Part of the $400 Million Program
July 2007		$		$ 50,008,332
August 2007	294,589	$ 61.10	294,589	$ 132,008,321(1)
September 2007	277,983	$ 64.76	277,983	$ 114,005,966
Total for July to September 2007	572,572	$ 62.88	572,572	

(1) As a result of the board authorized increase on August 9, 2007, the stock repurchase plan balance increased by $100,000,000, raising the maximum dollar value available for common stock repurchases from $32,008,321 to $132,008,321.

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Item 6. Exhibits

(a) Exhibits

31.1+ Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.

31.2+ Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.

32.1+ Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.

32.2+ Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.

+ Filed herewith.

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

HOLLY CORPORATION
(Registrant)

Date: November 8, 2007

/s/ P. Dean Ridenour
P. Dean Ridenour
Vice President and Chief Accounting
Officer` (Principal Accounting Officer)

/s/ Stephen J. McDonnell
Stephen J. McDonnell
Vice President and Chief Financial Officer
(Principal Financial Officer)