CONTANGO OIL & GAS CO
Form 10-Q
November 09, 2012

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2012
OR
.. 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 001-16317
CONTANGO OIL & GAS COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	95-4079863
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

3700 BUFFALO SPEEDWAY, SUITE 960 HOUSTON, TEXAS 77098
(Address of principal executive offices)
(713) 960-1901
(Registrant’s telephone number, including area code)

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 ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	ý	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
The total number of shares of common stock, par value $0.04 per share, outstanding as of November 1, 2012 was 15,194,952.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY REPORT ON FORM 10-Q
FOR THE THREE MONTHS ENDED SEPTEMBER 30, 2012
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All references in this Form 10-Q to the "Company", "Contango", "we", "us" or "our" are to Contango Oil & Gas Company and its wholly-owned subsidiaries. Unless otherwise noted, all information in this Form 10-Q relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2012 (thousands)	June 30, 2012
CURRENT ASSETS:		
Cash and cash equivalents	$137,784	$129,983
Accounts receivable:		
Trade receivables	28,332	29,688
Joint interest billings	4,695	4,768
Income taxes	12,327	4,510
Prepaid expenses	3,086	5,762
Other	1,062	502
Total current assets	187,286	175,213
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	555,680	561,713
Unproved properties	16,021	12,485
Furniture and equipment	216	213
Accumulated depreciation, depletion and amortization	(187,246)	(178,081)
Total property, plant and equipment, net	384,671	396,330
OTHER ASSETS:		
Investments in affiliates	46,197	52,827
Other	255	284
TOTAL ASSETS	$618,409	$624,654
CURRENT LIABILITIES:		
Accounts payable	$4,488	$3,084
Royalties and revenue payable	18,709	22,098
Accrued liabilities	5,319	6,796
Accrued exploration and development	32,611	2,334
Total current liabilities	61,127	34,312
DEFERRED TAX LIABILITY	110,778	118,010
ASSET RETIREMENT OBLIGATIONS	9,714	7,993
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50,000,000 shares authorized; 20,135,107 shares issued and 15,292,448 shares outstanding at September 30, 2012 and June 30, 2012	805	805
Additional paid-in capital	79,024	79,024
Treasury shares at cost (4,842,659 shares at September 30, 2012 and June 30, 2012)	(112,207)	(112,207)
Retained earnings	469,168	496,717
Total shareholders' equity	436,790	464,339
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$618,409	$624,654

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2012	2011
	(thousands, except per share amounts)	
REVENUES:		
Natural gas, oil and liquids sales	$29,765	$44,203
Total revenues	29,765	44,203
EXPENSES:		
Operating expenses	6,464	5,889
Exploration expenses	44,984	24
Depreciation, depletion and amortization	9,566	10,956
Impairment of natural gas and oil properties	8,410	—
General and administrative expenses	2,580	2,248
Total expenses	72,004	19,117
Gain from investments in affiliates, net of tax of $88	164	—
Other income/(expense)	(12)	(77)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(42,087)	25,009
Income tax benefit (provision)	14,538	(9,423)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(27,549)	15,586
DISCONTINUED OPERATIONS (NOTE 8)		
Discontinued operations, net of income taxes	—	(682)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$(27,549)	$14,904
NET INCOME (LOSS) PER SHARE:		
Basic		
Continuing operations	$(1.80)	$0.99
Discontinued operations	—	(0.04)
Total	$(1.80)	$0.95
Diluted		
Continuing operations	$(1.80)	$0.99
Discontinued operations	—	(0.04)
Total	$(1.80)	$0.95
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
Basic	15,292	15,639
Diluted	15,292	15,642

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30, 2012	
	2012	2011
	(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss) from continuing operations	$(27,549)	$15,586
Loss from discontinued operations, net of income taxes	—	(682)
Net income (loss)	(27,549)	14,904
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	9,566	10,956
Impairment of natural gas and oil properties	8,410	1,031
Exploration expenses	44,832	—
Deferred income taxes	(7,232)	(94)
Gain from investment in affiliates	(252)	—
Changes in operating assets and liabilities:		
Decrease in accounts receivable and other	1,355	2,285
Decrease in prepaids and other receivables	200	894
Decrease in accounts payable and advances from joint owners	(1,913)	(14,625)
Decrease in other accrued liabilities	(1,477)	(4,777)
Decrease (increase) in income taxes receivable, net	(7,817)	1,649
Other	(207)	366
Net cash provided by operating activities	17,916	12,589
CASH FLOWS FROM INVESTING ACTIVITIES:		
Natural gas and oil exploration and development expenditures	(17,205)	(11,476)
Investment in affiliates	(733)	(140)
Return of investments in affiliates	7,823	—
Net cash used in investing activities	(10,115)	(11,616)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Purchase of common stock	—	(13,532)
Net cash used in financing activities	—	(13,532)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	7,801	(12,559)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	129,983	150,007
CASH AND CASH EQUIVALENTS, END OF PERIOD	$137,784	$137,448
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for taxes, net of cash received	$600	$7,500
Cash paid for interest	$13	$37

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(Unaudited)

	Common Stock		Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
	Shares	Amount				
	(thousands)					
Balance at June 30, 2012	15,292	$805	$79,024	$(112,207)	$496,717	$464,339
Net loss	—	—	—	—	(27,549)	(27,549)
Balance at September 30, 2012	15,292	$805	$79,024	$(112,207)	$469,168	$436,790

The accompanying notes are an integral part of this consolidated financial statement

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information, pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”), including instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by GAAP for complete annual financial statements. In the opinion of management, all adjustments considered necessary for a fair statement of the unaudited consolidated financial statements have been included. All such adjustments are of a normal recurring nature. The consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in Contango Oil & Gas Company’s ("Contango" or the "Company") Form 10-K for the fiscal year ended June 30, 2012. The consolidated results of operations for the three months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the fiscal year ending June 30, 2013.

2. Business

We are a Houston-based, independent natural gas and oil company. Our core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet, using cash generated from our existing property base. We have an inventory of six offshore prospects and no debt.

In July 2012, we drilled two exploration wells (Ship Shoal 134 and South Timbalier 75) and no commercial hydrocarbons were found. For the three months ended September 30, 2012, we recorded exploration expenses of approximately $43.7 million, including leasehold costs, related to these two wells, with additional costs incurred in October and November 2012.

As of September 30, 2012, we had invested approximately $12.3 million with Alta Energy Canada Partnership, G.P. ("Alta Energy") for a 5% ownership interest in the Kaybob Duvernay shale play. We had also invested approximately $33.8 million with Exaro Energy III LLC ("Exaro") in the Jonah field in Wyoming, which is primarily development of proved reserves. In addition, as of September 30, 2012, the Company had invested approximately $8.8 million in leasehold costs in the Tuscaloosa Marine Shale ("TMS") for approximately 24,000 acres.

3. Summary of Significant Accounting Policies

The application of GAAP involves certain assumptions, judgments, decisions and estimates that affect reported amounts of assets, liabilities, revenues, expenses, contingencies and reserves. Actual results could differ from these estimates. Contango’s significant accounting policies are described below.

Successful Efforts Method of Accounting. The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. The provision for depreciation, depletion and amortization is based on the capitalized costs as determined above. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

Impairment of Long-Lived Assets. When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future net cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows based on the Company’s estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. For the three months ended September 30, 2012, we recorded an impairment expense of approximately $8.4 million related to proved properties. Of this amount, approximately $6.3 million related to our Ship Shoal 263 well and $2.1 million related to the Eugene

Island 24 platform and other properties. No impairment of proved properties was recognized in continuing operations for the three months ended September 30, 2011.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. For the three months ended September 30, 2012, the Company recognized impairment expense of approximately $6.6 million related to leasehold costs at our dry holes at Ship Shoal 134 and South Timbalier 75, plus an additional $1.2 million related to an unsuccessful exploration program in Jim Hogg County, Texas. These costs are included in total exploration expense of approximately $45.0 million, together with the drilling, plugging and abandoning costs for the two dry holes. No impairment of unproved properties was recognized during the three months ended September 30, 2011.

Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade investments having an original maturity of 90 days or less. As of September 30, 2012, the Company had approximately $137.8 million in cash and cash equivalents, all of which was held in non-interest bearing accounts.

Principles of Consolidation. The Company's consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries and affiliates, after elimination of all significant intercompany balances and transactions. Wholly-owned subsidiaries are consolidated. Exploration and development affiliates not wholly owned, such as 32.3% owned Republic Exploration, LLC ("REX"), are not controlled by the Company and are proportionately consolidated in the Company's financial statements.

Other Investments. The Company has a 19.5% ownership interest in Moblize Inc. ("Moblize") and a 2.0% ownership interest in Alta Energy. Both of these investments are accounted for using the cost method. The Company also has a 37% ownership interest in Exaro. The Company has two seats on the board of directors of Exaro, and has significant influence, but not control, over Exaro. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method.

The Company originally had a 45% ownership interest in Exaro upon its formation in April 2012. In August 2012, one of the other investors in Exaro exercised its right to assume $15 million of the Company's commitment by making a cash payment to the Company of $7.5 million and agreeing to assume $7.5 million of future commitment in Exaro. This lowered the Company's ownership interest to 37%. As of November 1, 2012, the Company had invested approximately $33.8 million in Exaro.

Recent Accounting Pronouncements. In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual and interim periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the disclosures in our financial statements.

Reclassifications. Certain reclassifications have been made to the amounts included in the consolidated financial statements as of June 30, 2012 and for the three months ended September 30, 2011, in order to conform to the 2012 presentation. These reclassifications were not material.

4. Natural Gas and Oil Exploration and Production Risk

The Company's future financial condition and results of operations will depend upon prices received for its natural gas and oil production and the cost of finding, acquiring, developing and producing reserves. Substantially all of the Company's production is sold under various terms and arrangements at prevailing market prices. Prices for natural gas and oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company's control.

Other factors that have a direct bearing on the Company's financial condition are uncertainties inherent in estimating natural gas and oil reserves and future hydrocarbon production and cash flows, particularly with respect to wells that have not been fully tested and with wells having limited production histories; the timing and costs of our future drilling; development and abandonment activities; access to additional capital; changes in the price of natural gas and oil; availability and cost of services and equipment; and the presence of competitors with greater financial resources and capacity.

5. Customer Concentration Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. Major purchasers of our natural gas and oil for the three months ended September 30, 2012 were ConocoPhillips Company, Shell Trading US Company, Exxon Mobil Oil Corporation, Enterprise Products Operating LLC, Crosstex Energy Services, JP Morgan

Ventures Energy Corporation and Trans Louisiana Gas Pipeline, Inc. Our sales to these companies are not secured with letters of credit and in the event of non-payment, we could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on our financial position, but there currently are numerous other potential purchasers of our production.

6. Net Income (Loss) per Common Share

A reconciliation of the components of basic and diluted net income (loss) per share of common stock is presented below:

	Three Months Ended September 30, 2012			Three Months Ended September 30, 2011		
	Loss	Shares	Per Share	Income (loss)	Shares	Per Share
	(thousands, except per share amounts)					
Income (loss) from continuing operations	$(27,549)	15,292	$(1.80)	$15,586	15,639	$0.99
Discontinued operations, net of income tax	—	15,292	—	(682)	15,639	(0.04)
Basic Earnings per Share:						
Net income (loss) attributable to common stock	$(27,549)	15,292	$(1.80)	$14,904	15,639	$0.95
Effect of potential dilutive securities:						
Stock options, net of shares assumed purchased	—	—		—	3	
Income (loss) from continuing operations	$(27,549)	15,292	$(1.80)	$15,586	15,642	$0.99
Discontinued operations, net of income tax	—	15,292	—	(682)	15,642	(0.04)
Diluted Earnings per Share:						
Net income (loss) attributable to common stock	$(27,549)	15,292	$(1.80)	$14,904	15,642	$0.95

7. Credit Facility

In October 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement"). The Credit Agreement currently has a $40 million hydrocarbon borrowing base and is available to fund the Company's exploration and development activities, as well as repurchase shares of common stock, pay dividends and fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and effective November 1, 2011, a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of September 30, 2012, the Company was in compliance with all covenants and had no borrowings outstanding under the Credit Agreement.

8. Discontinued Operations

In May 2011, the Company sold its 100% working interest (72.5% net revenue interest) in Rexer #1 and a 75% working interest (54.4% net revenue interest) in Rexer-Tusa #2 to Patara Oil & Gas LLC ("Patara"). B.A. Berilgen, a member of the Company's board of directors, is the Chief Executive Officer of Patara. In October 2011, the Company sold its remaining 25% working interest (18.4% net revenue interest) in Rexer-Tusa #2 to Patara. The sale was effective October 1, 2011. The Company has accounted for the sale of Rexer #1 and Rexer-Tusa #2 as discontinued operations as of December 31, 2011 and reclassified the results of operations for these two wells to discontinued operations for all periods presented as follows:

	Three Months Ended September 30, 2011
Results of Operations:	
Revenues	$—
Operating expenses	(10)
Exploration expenses	(1,031)
Impairment of natural gas and oil properties	(8)
Loss before income taxes	(1,049)
Income tax benefit	367
Loss from discontinued operations, net of income taxes	$(682)

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9. Income Taxes

The Company’s income tax provision for continuing operations consists of the following:

	Three Months Ended September 30, 2012	2011
Current tax provision (benefit):		
Federal	$(7,874)	$8,246
State	568	907
Total	$(7,306)	$9,153
Deferred tax provision (benefit):		
Federal	$(7,108)	$286
State	(124)	(16)
Total	$(7,232)	$270
Total tax provision (benefit):		
Federal	$(14,982)	$8,532
State	444	891
Total	$(14,538)	$9,423

10. Related Party Transactions

Juneau Exploration L.P. In April 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of Juneau Exploration, L.P. ("JEX") , had joined the Company’s board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango’s staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX will be paid an annual fee of $2.0 million. In August 2012, the Company's Chairman and Chief Executive Officer, Mr. Kenneth R. Peak, took a six month leave of absence, and the Board of Directors of the Company appointed Mr. Juneau as President and Acting Chief Executive Officer of the Company. Mr. Peak remains the Company's Chairman.

JEX has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest ("WI"), net revenue interest ("NRI"), and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX, excluding Mr. Juneau, except where otherwise noted.

Republic Exploration LLC. In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant’s working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

As of September 30, 2012, Contango, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Contango WI	Contango NRI	JEX WI	JEX NRI	REX WI	REX NRI	JEX Employees ORRI
Dutch #1 - #5	47.05%	38.12%	1.61%	1.29%	—%	—%	2.02%
Mary Rose #1	53.21%	40.45%	2.01%	1.51%	—%	—%	2.79%
Mary Rose #2 - #3	53.21%	38.67%	2.01%	1.44%	—%	—%	2.79%
Mary Rose #4	34.58%	25.49%	1.31%	0.95%	—%	—%	1.82%
Mary Rose #5	37.80%	27.88%	1.43%	1.04%	—%	—%	1.54%
Ship Shoal 263	100.00%	80.00%	—%	—%	—%	—%	3.33%

Vermilion 170	83.20 %	64.83 %	4.30 %	3.35 %	12.50 %	9.74 %	3.33%

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Below is a summary of payments received from (paid to) JEX and REX in the ordinary course of business in our capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types of payments with other well owners (in thousands):

	Three months ended September 30,			
	2012		2011	
	JEX	REX	JEX	REX
Revenue payments as well owners	$(1,133)	$(849)	$(1,283)	$(30)
Joint interest billing receipts	220	91	247	1,082

Below is a summary of payments received from (paid to) JEX and REX as a result of specific transactions between the Company, JEX and REX. While these payments are in the ordinary course of business, the Company did not have similar transactions with other well owners (in thousands):

	Three months ended September 30,			
	2012		2011	
	JEX	REX	JEX	REX
Reimbursement of certain costs	$(146)	$—	$(5)	$(10)
Prospect fees	—	—	(250)	—
Payments under advisory agreement dated April 1, 2012	(667)	—	—	—
REX distribution to members	—	323	—	—

As of September 30, 2012 and June 30, 2012, the Company's consolidated balance sheets included the following balances (in thousands):

	September 30, 2012		June 30, 2012	
	JEX	REX	JEX	REX
Accounts receivable:				
Trade receivables	$6	$1	$20	$18
Joint interest billings	151	142	158	92
Accounts payable:				
Royalties and revenue payable	(722)	(515)	(813)	(682)
Joint interest billings	(257)	—	—	—

In addition to the above, the Company paid Mr. Brad Juneau $28,000 during the three months ended September 30, 2012 for his services as a director of the Company.

11. Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Board approved a $100 million share repurchase program. All shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases are made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

During the three months ended September 30, 2011, the Company purchased 243,700 shares at an average price of $55.53 per share, for a total of approximately $13.5 million. The $100 million share repurchase program concluded in October 2011.

$50 Million Share Repurchase Program

In September 2011, the Board approved a $50 million share repurchase program, effective upon completion of purchases under the Company’s $100 million share repurchase program. The purchases made under the $50 million share repurchase

program will be subject to the same terms and conditions as purchases made under the $100 million share repurchase program. No shares were repurchased during the three months ended September 30, 2012.

In total, under both share repurchase programs combined, as of September 30, 2012, the Company had purchased approximately 2.3 million shares of its common stock at an average cost per share of $46.67, and 45,000 stock options, for a total of approximately $105.8 million, bringing its total share count as of September 30, 2012 to 15,292,448 shares of common stock outstanding.

12. Subsequent Events

In October 2012, the Company paid approximately $33.9 million of the costs associated with its dry holes at Ship Shoal 134 and South Timbalier 75. An additional $4.3 million was paid in November 2012. Also, in October 2012, the Company paid the final $4.3 million owed to the BOEM for the six lease blocks acquired at the Central Gulf of Mexico Lease Sale 216/222.

In October 2012, the Company invested approximately $4.3 million to acquire acreage and a 25% working interest to drill its first horizontal well with Goodrich Petroleum Company ("Goodrich") in the Tuscaloosa Marine Shale. Goodrich will act as operator.

In October 2012, the Company purchased 97,496 shares of its common stock under the Company's $50 million share repurchase program, for approximately $5.0 million. As of November 1, 2012, under both share repurchase programs combined, the Company had purchased approximately 2.4 million shares of its common stock at an average cost per share of $46.84 and 45,000 stock options, for a total of approximately $110.8 million, bringing its total share count to 15,194,952 shares of common stock outstanding.

As of September 30, 2012, the Company had invested approximately $12.3 million in Alta Energy to drill in the Kaybob Duvernay shale in Alberta, Canada. In November 2012, we invested an additional $0.8 million, bringing the Company's total investment in Alta Energy to approximately $13.1 million. Contango has a 5% interest in the Kaybob Duvernay project.

Available Information

General information about us can be found on our website at www.contango.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission (“SEC”).

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and the accompanying notes and other information included elsewhere in this Form 10-Q and in our Form 10-K for the fiscal year ended June 30, 2012, previously filed with the SEC.

Executive Overview

Contango Oil & Gas Company (“Contango” or the “Company”) is a Houston-based, independent natural gas and oil company. Our core business is to explore, develop, produce and acquire natural gas and oil properties onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet, using cash generated from our existing property base. We have no debt.

During the three months ended September 30, 2012, we drilled two exploration wells with an expected total drilling cost of $45.4 million and leasehold costs of $6.6 million, and no commercial hydrocarbons were found. Our current revenues, net of general and administrative costs and lease operating expenses, is approximately $7 million per month. We have an inventory of six offshore prospects that we plan to begin drilling in mid-2013 as permits are received and a drilling rig becomes available. Our offshore production is currently averaging approximately 79.7 million cubic feet equivalent per day ("Mmcfed").

Additionally, we have invested approximately $13.1 million with Alta Energy Canada Partnership, G.P. ("Alta Energy") for a 5% ownership interest in the Kaybob Duvernay shale play. We have also invested approximately $33.8 million with Exaro Energy III LLC ("Exaro") in the Jonah field in Wyoming, which is primarily development of proved reserves. In addition, the Company has invested approximately $8.9 million in leasehold costs in the Tuscaloosa Marine Shale ("TMS") and $4.2 million in drilling costs for a 25% working interest in the Goodrich Crosby 12-1H well which should provide whole core data and other data to evaluate our acreage position in the TMS play in Louisiana and Mississippi. Our current leasehold in this play is approximately 24,000 acres. Each of these items is further detailed below.

Exploration Program Summary

On July 3, 2012, we spud our Ship Shoal 134 prospect ("Eagle") with the Hercules 205 rig. On October 19, 2012, we announced that we had reached total depth on Eagle and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. We expect to incur expenses of approximately $29.0 million as a result of drilling, plugging and abandoning this well, including approximately $6.3 million in leasehold costs. For the three months ended September 30, 2012, we incurred approximately $26.9 million of these costs. We expect to incur the remaining $2.1 million during the three months ended December 31, 2012. Of this $29.0 million, only the leasehold costs of $6.3 million had been paid by September 30, 2012. We paid $16.6 million in October 2012 and an additional $3.3 million in November 2012. We expect to pay the remaining $2.8 million by the end of December 31, 2012.

On July 10, 2012 we spud our South Timbalier 75 prospect ("Fang") with the Spartan 303 rig. On October 30, 2012, we announced that we had reached total depth on Fang and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. We expect to incur expenses of approximately $23.0 million as a result of drilling, plugging and abandoning this well, including approximately $0.3 million in leasehold costs. For the three months ended September 30, 2012, we incurred approximately $16.8 million of these costs. We expect to incur the remaining $6.2 million during the three months ended December 31, 2012. Of this $23.0 million, only the leasehold costs of $0.3 million had been paid by September 30, 2012. We paid $17.3 million in October 2012 and an additional $1.0 million in November 2012. We expect to pay the remaining $4.4 million by the end of December 31, 2012. This prospect was a farm-in and the lease was never earned as a result of the dry hole.

Before drilling Eagle and Fang, our previous two prospects were discoveries. We spud Ship Shoal 263 in October 2009 and began production in June 2010. Additionally, we spud Vermilion 170 in February 2011 and began producing in September 2011. Due to the delay in receiving permits and rig availability after the Deepwater Horizon Incident, it has taken us over a year to spud new wells.

On June 20, 2012, the Company was the apparent high bidder on six lease blocks at the Central Gulf of Mexico Lease Sale 216/222 and has been awarded all six blocks. The Company bid an aggregate amount of approximately $11 million on the following six blocks:

- East Cameron 124
- Eugene Island 31
- Eugene Island 260
- Ship Shoal 83
- Ship Shoal 255
- South Timbalier 110

Of this $11.0 million, approximately $6.7 million had been paid by September 30, 2012. We paid the remaining $4.3 million in October 2012. We expect to begin drilling these prospects in mid-2013, depending on permitting and rig availability. We will have a one-rig drilling program and expect to drill all prospects sequentially, which should take approximately 18 months. Additionally, we will continue to evaluate new prospects and will be prepared to place bids at the next lease sale in March 2013. Until we start drilling in mid-2013, our plan is to accumulate cash from our producing wells to provide future funding for these six prospects from cash flows from operations and cash on hand. As of November 1, 2012, we had approximately $96.5 million of cash, $40.0 million of unused borrowing capacity, and no debt.

Our Strategy

Our exploration strategy is predicated upon two core beliefs: (1) that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers and (2) that virtually all the exploration and production industry’s value creation occurs through the drilling of successful exploratory wells. As a result, our business strategy includes the following elements:

Funding exploration prospects generated by Juneau Exploration, L.P., our alliance partner. We depend primarily upon our alliance partner, Juneau Exploration, L.P. (“JEX”), for prospect generation expertise. JEX is experienced and has a successful track record in exploration.

Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in exploration of i) offshore Gulf of Mexico prospects and ii) conventional and unconventional onshore plays. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status.

Sale of proved properties. From time-to-time as part of our business strategy, we have sold and in the future expect to continue to sell some or a substantial portion of our proved reserves and assets to capture current value, using the sales proceeds to further our exploration activities. Since its inception, the Company has sold approximately $524 million worth of natural gas and oil properties, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, and as a source of funds for potentially higher rate of return natural gas and oil exploration opportunities.

Controlling general and administrative and geological and geophysical costs. Our goal is to be among the most efficient in the industry in revenue and profit per employee and among the lowest in general and administrative costs. We plan to continue outsourcing our geological, geophysical, and reservoir engineering and land functions, and partnering with cost efficient operators. We have eleven employees.

Structuring incentives to drive behavior. We believe that equity ownership aligns the interests of our employees and stockholders. Our directors and executive officers beneficially own or have voting control over approximately 14% of our common stock.

Exploration Alliance with JEX

JEX is a private company formed for the purpose of generating offshore and onshore domestic natural gas and oil prospects for the Company, either directly, or via our 32.3% owned affiliated company, Republic Exploration LLC (“REX”) (see “Offshore Gulf of Mexico Exploration Joint Ventures” below). In addition to generating prospects, JEX occasionally evaluates exploration prospects generated by third-party independent companies. Once we agree to a prospect from JEX, REX or a third-party, we enter into a participation agreement and joint operating agreement specifying each participant's working interest, net revenue interest, and description of when such interests are earned, as well as allocating an overriding royalty interest of up to 3.33% to benefit employees of JEX.

On April 10, 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company's board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX will be paid an annual fee of $2.0 million and JEX, or employees of JEX, will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

Offshore Gulf of Mexico Exploration Joint Ventures

Contango, through its wholly-owned subsidiary Contango Operators, Inc. ("COI"), and its partially-owned subsidiary REX, conducts exploration activities in the Gulf of Mexico. As of November 1, 2012, Contango, through COI and REX, had an interest in 21 offshore leases. See "Offshore Properties" for additional information on our offshore properties.

Contango Operators, Inc.

COI acquires leasehold acreage, drills and operates our wells in the Gulf of Mexico. Additionally, COI may acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, under farm-out agreements, or similar agreements, with REX, JEX and/or third parties.

As of November 1, 2012, the Company's offshore production was approximately 79.7 Mmcfed, net to Contango, which consists mainly of seven federal and five State of Louisiana wells in the shallow waters of the Gulf of Mexico. These 12 operated wells produce through the following four platforms:

Eugene Island 24 Platform

This third-party owned and operated production platform at Eugene Island 24 was designed with a capacity of 100 million cubic feet per day ("Mmcfd") and 3,000 barrels of oil per day ("bopd"). This platform services production from the Company's Dutch #1, #2 and #3 federal wells. From this platform, the gas flows through an American Midstream pipeline into a third-party owned and operated on-shore processing facility at Burns Point, Louisiana, and the condensate flows via an ExxonMobil pipeline to on-shore markets and multiple refineries. As of November 1, 2012, we were producing approximately 20.0 Mmcfed, net to Contango, from this platform.

The Company recently finished laying 6" auxiliary flowlines from the Dutch #1, #2, and #3 wells to our Eugene Island 11 Platform (see below) and is in the process of redirecting production from the Eugene Island 24 Platform to the Eugene Island 11 Platform. Our cost estimate for the installation of these three flowlines is $2.5 million, net to Contango. As of September 30, 2012, the Company had incurred approximately $2.2 million to install these flowlines.

Eugene Island 11 Platform

Our Company-owned and operated production platform at Eugene Island 11 was designed with a capacity of 500 Mmcfd and 6,000 bopd. In September 2010 the Company completed installing a companion platform and two pipelines adjacent to the Eugene Island 11 platform to be able to access alternate markets. These platforms service production from the Company's five Mary Rose wells which are all located in state of Louisiana waters, as well as our Dutch #4 and Dutch #5 wells which are both located in federal waters. From these platforms, we can flow gas to the American Midstream pipeline via our 8" pipeline, which has been designed with a capacity of 80 Mmcfd, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. We can flow our condensate via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Alternatively, our gas and condensate can flow to our Eugene Island 63 auxiliary platform via our 20" pipeline, which has been designed with a capacity of 330 Mmcfd and 6,000 bopd, and then from there to third-party owned and operated on-shore processing facilities near Patterson, Louisiana, via an ANR pipeline. As of November 1, 2012, we were producing approximately 43.9 Mmcfed, net to Contango, from this platform.

Based on production and decline rates, the Company has recently determined the need to place its Dutch and Mary Rose wells on compression in 2013. The Company is in the process of designing and building a large turbine type compressor for the platform at an estimated cost of $6.8 million, net to Contango. This compressor will be of sufficient capacity to service all ten of the Company's Dutch and Mary Rose wells. As of September 30, 2012, the Company had incurred approximately $2.4 million to design and build the compressor, which is expected to be installed in May 2013.

Ship Shoal 263 Platform

Our Company-owned and operated platform at Ship Shoal 263 was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services natural gas and condensate production from our Nautilus well, which both flow via the Transcontinental Gas Pipeline to onshore processing plants. As of November 1, 2012, we were producing approximately 2.5 Mmcfed, net to Contango, from this platform.

Vermilion 170 Platform

Our Company-owned and operated platform at Vermilion 170 was designed with a capacity of 60 Mmcfd and 2,000 bopd. This platform services natural gas and condensate production from our Swimmy well which began producing in September 2011. The production flows via the Sea Robin Pipeline to onshore processing plants. As of November 1, 2012, we were producing approximately 13.3 Mmcfed, net to Contango, from this platform.

Based on current production and decline rates, the Company has determined the need to place its Vermilion 170 well on compression in 2013, at a cost of $1.4 million, net to Contango. As of September 30, 2012, the Company had incurred approximately $0.8 million to install a compressor to service its Swimmy well, which is expected to be completed by December 2012.

Republic Exploration LLC

In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects for the Company and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

REX currently has a 25.0% working interest (“WI”), and a 20.0% net revenue interest (“NRI”), in a well at West Delta 36, which is operated by a third party.

Offshore Properties

Producing Properties. The following table sets forth the interests owned by Contango through its affiliated entities in the Gulf of Mexico which were capable of producing natural gas or oil as of November 1, 2012:

Area/Block	WI		NRI		Status
Eugene Island 10 #D-1 (Dutch #1)	47.05	%	38.1	%	Producing
Eugene Island 10 #E-1 (Dutch #2)	47.05	%	38.1	%	Producing
Eugene Island 10 #F-1 (Dutch #3)	47.05	%	38.1	%	Producing
Eugene Island 10 #G-1 (Dutch #4)	47.05	%	38.1	%	Producing
Eugene Island 10 #I-1 (Dutch #5)	47.05	%	38.1	%	Producing
S-L 18640 #1 (Mary Rose #1)	53.21	%	40.5	%	Producing
S-L 19266 #1 (Mary Rose #2)	53.21	%	38.7	%	Producing
S-L 19266 #2 (Mary Rose #3)	53.21	%	38.7	%	Producing
S-L 18860 #1 (Mary Rose #4)	34.58	%	25.5	%	Producing
S-L 19266 #3 & S-L 19261 (Mary Rose #5)	37.80	%	27.6	%	Intermittent
Ship Shoal 263 (Nautilus)	100.00	%	80.0	%	Producing
Vermilion 170 (Swimmy)	87.24	%	68.0	%	Producing
West Delta 36 (produced via REX)	8.1	%	6.5	%	Producing

Leases. The following table sets forth the working interests owned by Contango and affiliated entities in non-developed leases in the Gulf of Mexico as of November 1, 2012.

Area/Block	WI		Lease Date	Expiration Date
Eugene Island 11	53.21	%	Dec-07	Dec-12
East Breaks 369 (Dry Hole)	(1	)	Dec-03	Dec-13
South Timbalier 97 (via REX)	32.30	%	Jun-09	Jun-14
Ship Shoal 121	100.00	%	Jul-10	Jul-15
Ship Shoal 122	100.00	%	Jul-10	Jul-15
Brazos Area 543	100.00	%	Mar-12	Mar-17
East Cameron 124	100.00	%	Sept-12	Sept-17
Eugene Island 31	100.00	%	Oct-12	Oct-17
Ship Shoal 83	100.00	%	Oct-12	Oct-17
South Timbalier 110	100.00	%	Oct-12	Oct-17
Eugene Island 260	100.00	%	Nov-12	Nov-17
Ship Shoal 255	100.00	%	Nov-12	Nov-17
Ship Shoal 134 (Dry Hole)	100.00	%	(2)	(2)

(1) Farm-out. COI retains a 2.41% ORRI

(2) Purchased deep rights. Lease is held by production from shallow wells owned by third-party

Onshore Exploration and Properties

Alta Energy Canada Partnership, G.P.

In April 2011, the Company announced a commitment to invest up to $20 million over two years in Alta Energy, a venture that will acquire, explore, develop and operate onshore unconventional oil and natural gas shale assets in North America. As of November 1, 2012, we had invested approximately $13.1 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. Alta Energy has built one of the largest acreage blocks in the core of the play. As of November 1, 2012, Alta Energy had drilled four vertical test wells and taken whole cores on two of those. Alta Energy also successfully drilled its first horizontal well and anticipates completion by the end of 2012. Alta Energy will soon spud its second horizontal well and plans to continue an evaluative drilling and completion program in 2013. Contango has a 5% interest in the Kaybob Duvernay project.

Exaro Energy III LLC

In April 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the “LLC Agreement”) in connection with the formation of Exaro . Pursuant to the LLC Agreement, the Company had committed to invest up to $82.5 million in cash in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million, or a 45% ownership interest in Exaro.

In August 2012, one of the other investors in Exaro exercised its right to assume $15 million of the Company's commitment, which lowered the Company's commitment to $67.5 million and its ownership interest to 37%. As of September 30, 2012, the Company had invested approximately $33.8 million in Exaro. Of this amount, approximately $8.0 million had been spent on drilling, development, and general and administrative costs.

Exaro has entered into an Earning and Development Agreement with Encana Oil & Gas (USA) Inc. (“Encana”) to provide funding of up to $380 million to continue the development drilling program in a defined area of Encana’s Jonah field asset located in Sublette County, Wyoming. This funding will be comprised of the $182.5 million investment described above, debt, and cash flow from operations. Encana will continue to be the operator of the field and upon investing the full amount of the $380 million, Exaro will have earned 32.5% of Encana’s working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

The Exaro-Encana venture currently has three rigs drilling and has completed and achieved first production on ten wells to date. Four additional wells are being hooked up to production. Production is currently approximately 3.0

Mmcfed, net to Contango. The drilling project is progressing on schedule. As of September 30, 2012, there were no material natural gas or oil reserves associated with our investment in Exaro. For the three months ended September 30, 2012, Exaro had income of approximately $628,000, of which approximately $164,000 was recognized in the Company's consolidated statement of operations (net of $88,000 in taxes) for the three months ended September 30, 2012.

Tuscaloosa Marine Shale

As of November 1, 2012, the Company had invested approximately $8.9 million to lease approximately 24,000 acres in the TMS, a shale play in central Louisiana and Mississippi. The TMS is an oil focused play and we plan to participate in third-party operated wells with a small working interest prior to initiating an operated, high interest drilling program.

In October 2012, the Company became a 25% non-operating working interest partner with Goodrich Petroleum Company LLC ("Goodrich") in the TMS. We have invested approximately $4.3 million, net to Contango, to acquire acreage and participate in our first horizontal well, the Crosby 12H-1. For evaluation purposes, we will drill a pilot hole, perform an open-hole evaluation and obtain a conventional core over the TMS interval. The data we obtain from this well will help us evaluate our TMS acreage and develop a plan for drilling and operating future wells.

Jim Hogg County, Texas

We recently expended approximately $1.2 million in an exploration program with a large south Texas mineral owner involving acreage in Jim Hogg County, Texas. We have determined this program to be unsuccessful and will not invest additional funds. For the three months ended September 30, 2012, the Company included these costs in exploration expenses.

Risk and Insurance Program Update

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

We expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident of 2010. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor the expected regulatory and legislative response and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows.

We carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. As a result of the incident, we have increased our well control coverage from $75 million to $100 million on certain wells, which covers control of wells, pollution cleanup and consequential damages. We have increased our general liability coverage from $100 million to $150 million, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death. We have also increased our Oil Spill Financial Responsibility coverage from $35 million to $150 million, which covers additional pollution cleanup and third party claims coverage.

Health, Safety and Environmental Program. The Company’s Health, Safety and Environmental (“HS&E”) Program is supervised by an operating committee of senior management to insure compliance with all state and federal regulations. In addition, to support the operating committee, we have contracted with J. Connors Consulting (“JCC”) to manage our regulatory process. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico regulatory process, preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills to oil and gas companies and pipeline operators.

For our Gulf of Mexico operations, we have a Regional Oil Spill Plan in place with the Bureau of Ocean Energy Management ("BOEM"). Our response team is trained annually and is tested through annual spill drills given by the BOEM. In addition, we have a contract in place with O’Brien’s Response Management (“O’Brien’s”). O’Brien’s maintains a

24/7 manned incident command center located in Slidell, LA. Upon the occurrence of an oil spill, the Company's spill program is initiated by notifying O'Brien's that we have an emergency. While the Company would focus on source control of the spill, O'Brien's would handle all communication with state and federal agencies as well as U.S. Coast Guard notifications.

If a spill were to occur, we have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at various bases in Texas and Louisiana. The CGA equipment stockpile includes skimming vessels which can operate in open seas or shallow waters; protective booming to use in open seas or near shorelines; communication equipment; dispersants; and boat spray systems to apply dispersants. CGA also has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses. Additionally, CGA provides wildlife rehabilitation services and a forward command center. Some of the CGA equipment includes:

- HOSS Barge: the largest purpose-built skimming barge in the United States with 4,000 barrels of storage capacity.
- Fast Response System (FRU): a self-contained skimming system for use on vessels of opportunity. CGA has nine of these units.
- Fast Response Vessels (FRV): four 46 foot FRVs with cruise speeds of 20-25 knots that have built-in skimming troughs and cargo tanks, outrigger skimming arms, navigation and communication equipment.

In addition to being a member of CGA, we have contracted with Wild Well Control for source control at the wellhead if required. Wild Well Control is one of the world's leading providers of firefighting, well control, engineering, and training services.

Safety and Environmental Management System ("SEMS")

The Company has developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the Outer Continental Shelf ("OCS"), as required by the Bureau of Safety and Environmental Enforcement ("BSEE"). Full implementation of the following thirteen mandatory elements of the American Petroleum Institute's Recommended Practice 75 (API RP 75) was required on or before November 15, 2011:

- General Provisions
- Safety and Environmental Information
- Hazards Analyses
- Management of Change
- Operating Procedures
- Safe Work Practices
- Training
- Mechanical Integrity
- Pre-Startup Review
- Emergency Response and Control
- Investigation of Accidents
- Audits
- Records and Documentation

Our SEMS program identifies, addresses, and manages safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company has established goals, performance measures, training and accountability for its implementation, and provides necessary resources for an effective SEMS, as well as review the adequacy and effectiveness of the SEMS program. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. We have contracted with Island Technologies Inc. to manage our SEMS program for production operations.

The BSEE enforces the SEMS requirements via audits. We must have our SEMS program audited by either an independent third-party or our designated and qualified personnel within 2 years of the initial implementation and at least once every 3 years thereafter. Failure of an audit may force us to shut-in our Gulf of Mexico operations.

Employees

We have eleven employees, all of whom are full time employees. The Company outsources its human resources function to Insperity, Inc. and all of the Company's employees are co-employees of Insperity, Inc.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 3 to the consolidated financial statements included in this Quarterly Report on Form 10-Q. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to its natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

Successful Efforts Method of Accounting. Our application of the successful efforts method of accounting for our natural gas and oil business activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Reserve Estimates. While we are reasonably certain of recovering our reported reserves, the Company's estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing natural gas and oil prices, operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company's natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties. Actual production, revenues and expenditures with respect to the Company's reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company's proved reserve estimate at September 30, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $0.5 million, $1 million and $1.7 million, respectively.

Impairment of Natural Gas and Oil Properties. The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company's estimate of future natural gas and oil prices, operating costs, and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the consolidated financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between consolidated financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

MD&A Summary Data

The following table shows the relationship between our produced volumes and the revenues they derive:

	Three Months Ended September 30,					
	2012			2011		
	(thousands, except percentage)					
Natural gas volumes (Mcf)	4,767	76.02	%	5,159	76.31	%
Condensate and NGL volumes (Mcfe)	1,504	23.98	%	1,602	23.69	%
Total volumes	6,271			6,761		
Natural gas revenues	$14,076	47.29	%	$22,262	50.36	%
Condensate and NGL revenues	15,689	52.71	%	21,941	49.64	%
Total revenues	$29,765			$44,203		

The table below sets forth average daily production data in Mmcfed from our offshore wells for each of the periods presented:

	Three Months Ended				
	September 30, 2011	December 31, 2011	March 31, 2012	June 30, 2012	September 30, 2012
Dutch and Mary Rose Wells	63.1	66.2	59.3	67.5	54.2
Ship Shoal 263 Well (Nautilus)	7.7	10.9	7.8	7.6	3.5
Vermilion 170 Well (Swimmy)	2.3	17.2	15.3	15.5	10.5
Non-operated wells	0.4	0.2	0.3	0.2	—
	73.5	94.5	82.7	90.8	68.2

Dutch and Mary Rose Wells

The decrease in production during the three months ended March 31, 2012 was due to shutting in our Dutch #1, #2 and #3 wells for a total of 10 days for maintenance and to repair a small pipeline leak. The decrease in production during the three months ended September 30, 2012 was due to shutting in our Eugene Island 11 platform for 12 days and shutting in the Eugene Island 24 platform for seven days due to flowline installation, problems at third-party, onshore facilities, and Hurricane Isaac evacuations. Additionally, our Dutch #4 well was shut-in for nine days to perform a workover, and our Mary Rose #4 well was shut-in for five days for flowline repairs. As of November 1, 2012, these ten wells were flowing approximately 63.9 Mmcfed, net to Contango.

Ship Shoal 263 Well (Nautilus)

During the three months ended September 30, 2011, production at Ship Shoal 263 was temporarily shut-in due to a leak on a third-party owned and operated pipeline. Since December 31, 2011, production at this well has been slowly decreasing due to overheating, scaling problems, and water production. The well has also been shut-in several times over the past few months for production logging and chemical treatment. As of November 1, 2012, the well was flowing at approximately 2.5 Mmcfed, net to Contango.

As of September 30, 2012, the net book value of our Ship Shoal 263 well exceeded the future undiscounted cash flows associated with the reserves at Ship Shoal 263. Accordingly, the Company recognized an impairment expense of approximately $6.3 million for the difference between the net book value of Ship Shoal 263 and the fair value of its reserves.

Vermilion 170 Well (Swimmy)

Our Vermilion 170 well began production in September 2011. This well was shut-in for a total of five days during the three months ended September 30, 2012 for Hurricane Isaac evacuations, high pipeline pressures due to pigging operations, equipment testing, and an additional 13 days for compressor installation. As of November 1, 2012, this well was flowing at approximately 13.3 Mmcfed, net to Contango.

The table below sets forth revenue, expense and production data for the three months ended September 30, 2012 and 2011.

	Three Months Ended September 30,		
	2012	2011	Change
	(thousands, except percent change, average sales price and selected data per Mcfe)		
Revenues:			
Natural gas and oil sales	$29,765	$44,203	(33)%
Total revenues	$29,765	$44,203	(33)%
Production:			
Natural gas (million cubic feet)	4,767	5,159	(8)%
Oil and condensate (thousand barrels)	101	131	(23)%
Natural gas liquids (thousand gallons)	6,287	5,710	10 %
Total (million cubic feet equivalent)	6,271	6,761	(7)%
Natural gas (million cubic feet per day)	51.8	56.1	(8)%
Oil and condensate (thousand barrels per day)	1.1	1.4	(23)%
Natural gas liquids (thousand gallons per day)	68.3	62.1	10 %
Total (million cubic feet equivalent per day)	68.2	73.5	(7)%
Average Sales Price:			
Natural gas (per thousand cubic feet)	$2.95	$4.28	(31)%
Oil and condensate (per barrel)	$105.31	$105.55	*
Natural gas liquids (per gallon)	$0.80	$1.44	(44)%
Total (per thousand cubic feet equivalent)	$4.74	$6.54	(28)%
Summary of Financial Information:			
Operating expenses	$6,464	$5,889	10 %
	$44,984	$24	100 %

Exploration expenses Depreciation, depletion and amortization Impairment of natural gas and oil properties	$9,566	$10,956	(13)%

We recorded an $18.0 million provision for credit losses during the second quarter of 2009 compared to a $14.0 million provision in the first quarter of 2009 and a $3.5 million provision during the second quarter of 2008. Such provisions were based on our reserve methodology, took the above factors into consideration, and considered our analysis and judgment of the inherent risks in our portfolio and the effects current market conditions have had on our borrowers. We recorded a $32.0 million provision for credit losses during the first six months of 2009 compared to a $29.5 million provision in the same period of 2008. The 2008 provision for credit losses included $16.2 million related to the sale of $34.1 million of residential construction nonaccrual loans at a price of $17.9 million.

Increased provisions for credit losses may be required in the future based on charge-off experience, loan and unfunded commitment growth and the effect that changes in economic conditions, such as inflation, commodity prices, unemployment, consumer spending, market interest rate levels and real estate values have on the ability of borrowers to repay their loans, and other conditions specific to our borrowers' businesses.

Noninterest Income. The following table summarizes noninterest income by category for the periods indicated:

	Quarter Ended				
	June 30, 2009	**March 31, 2009**	**December 31, 2008**	**September 30, 2008**	**June 30, 2008**
	(Dollars in thousands)				
Service charges and fees on deposit accounts	$3,009	$ 3,149	$ 3,420	$ 3,165	$3,205
Other commissions and fees	1,746	1,685	2,062	1,884	1,812
Loss on sale of loans, net					(572)
Gain on sale of securities, net				81	
Increase in cash surrender value of life insurance	394	439	584	632	617
Other income	224	808	476	290	302
Total noninterest income	$5,373	$ 6,081	$ 6,542	$ 6,052	$5,364

Second quarter of 2009 compared to first quarter of 2009 and second quarter of 2008

Noninterest income for the second quarter of 2009 totaled $5.4 million compared to $6.1 million in the first quarter of 2009 and $5.4 million for the second quarter of 2008. The decrease between the 2009 quarters is due primarily to life insurance proceeds of $536,000 received during the first quarter of 2009; there was no similar item in any of the other periods presented. Noninterest income remained

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relatively flat for the second quarter of 2009 when compared to the same period of 2008 due to lower loss on sale of loans and lower aggregate service charges and fees on deposit accounts. The general decline in the appreciation of the cash surrender value of life insurance for the periods presented is a result of the policies earning at lower crediting rates and lower asset balances due to death benefit receipts and policy surrenders.

Six Months Analysis

Noninterest income decreased for the six months ended June 30, 2009 to $11.5 million from the $11.8 million earned during the same period in 2008. The decrease in noninterest income resulted largely from lower interest return on the cash surrender values of our life insurance policies and lower service charge income.

Noninterest Expense. The following table summarizes operating noninterest expense and noninterest expense by category for the periods indicated:

	Quarter Ended				
	June 30, 2009	**March 31, 2009**	**December 31, 2008**	**September 30, 2008**	**June 30, 2008**
	(Dollars in thousands)				
Compensation	$ 18,394	$ 19,331	$ 15,088	$ 19,332	$ 18,919
Occupancy	6,462	6,386	6,410	6,321	5,930
Data processing	1,677	1,628	1,590	1,495	1,604
Other professional services	1,486	1,524	1,688	1,768	1,669
Business development	625	725	789	650	849
Communications	688	693	766	745	816
Insurance and assessments	3,871	1,598	1,148	1,025	810
Other real estate owned, net	9,231	997	748	1,369	127
Intangible asset amortization	2,367	2,247	2,332	2,274	2,484
Reorganization and lease charges		1,215			258
Legal settlement					780
Other	3,130	2,625	3,260	2,878	3,100
Total operating noninterest expense	47,931	38,969	33,819	37,857	37,346
Goodwill write-off					486,701
Total noninterest expense	$ 47,931	$ 38,969	$ 33,819	$ 37,857	$ 524,047
Efficiency ratio	85.5%	71.0%	59.1%	62.0%	857.2%
Operating efficiency ratio	85.5%	71.0%	59.1%	62.0%	61.1%

Second quarter of 2009 compared to first quarter of 2009

Noninterest expense increased $8.9 million to $47.9 million for second quarter of 2009 from the first quarter. Such increase is due mostly to OREO expenses and higher FDIC deposit insurance costs. The second quarter OREO expenses include holding costs of $526,000, carrying value write-downs of $7.2 million and net realized losses of $1.5 million resulting from the sale of OREO. The FDIC special assessment for all banks was to be accrued in the second quarter; such special assessment was based on asset size and it totaled $2.0 million for Pacific Western Bank. Compensation costs declined in the linked 2009 quarters as we reduced our staffing levels in response to the lending environment. The first quarter of 2009 reorganization and lease charges of $1.2 million related to staff reductions, premises costs related to the planned closing of two banking offices and additional rent for a discontinued acquired office; there were no such items in the second quarter of 2009.

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Noninterest expense includes amortization of restricted stock, which is included in compensation, and intangible asset amortization. Amortization of restricted stock totaled $1.9 million for the second quarter of 2009 compared to $2.2 million for the first quarter of 2009. Amortization expense for restricted stock awards is estimated to be $7.9 million for 2009. Intangible asset amortization totaled $2.4 million for the second quarter of 2009 and $2.2 million for the first quarter of 2009 and is estimated to be $9.2 million for 2009. The 2009 estimates of both restricted stock award expense and intangible asset amortization are subject to change.

Second quarter of 2009 compared to second quarter of 2008

Noninterest expense decreased $476.1 million for second quarter of 2009 when compared to the same period of 2008. Noninterest expense for the second quarter of 2008 included a $486.7 million charge to earnings for the goodwill write-off. Operating noninterest expense (defined as reported noninterest expense excluding goodwill write-offs) for the second quarter of 2009 totaled $47.9 million compared to $37.3 million for the second quarter of 2008. The $10.6 million increase is due mostly to higher OREO expenses and FDIC insurance assessments.

Six Months Analysis

Noninterest expense for the six months ended June 30, 2009 totaled $86.9 million compared to $834.3 million for the same period in 2008. The decrease is due to the goodwill write-off of $761.7 million incurred in the first half of 2008; there was no such write-off in 2009. Excluding this write-off, operating noninterest expense was $72.6 million for the first six months of 2008. The $14.3 million increase in operating noninterest expense is due to higher OREO costs of $10.1 million, higher insurance costs of $4.1 million, and higher reorganization costs of $957,000. The majority of the OREO costs were incurred in the second quarter of 2009. The higher insurance costs relate entirely to higher FDIC deposit insurance premiums, including the cost to participate in the Temporary Liquidity Guarantee Program and the second quarter of 2009 special FDIC assessment.

Income Taxes. The effective tax rate for the second quarter of 2009 was 41.7% compared to 23.3% for the first quarter of 2009. Tax credits on certain investments, tax-exempt income and other tax adjustments have a greater effect on our effective tax rates during periods of net losses or minimal net earnings. The Company's blended Federal and State statutory rate is 42.0%.

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Balance Sheet Analysis

Loans. Gross loans total $3.9 billion at June 30, 2009. Our loan portfolio's value and credit quality is affected in large part by real estate trends in Southern California which have been negative for the last several quarters. The real estate construction category includes commercial real estate loans totaling $319.9 million and residential real estate construction loans totaling $225.0 million, of which $208.8 million is nonowner occupied. See also Balance Sheet Analysis *Credit Quality* for further information on nonowner occupied residential construction loan exposure. The real estate mortgage loan category includes loans secured by commercial real estate totaling $2.3 billion and loans secured by residential real estate totaling $245.6 million.

At June 30, 2009, the SBA loan portfolio totaled $165.0 million and was composed of $124.1 million in SBA 504 loans and $40.9 million in SBA 7(a) and Express loans. The SBA 504 loans are included in the real estate mortgage category and the SBA 7(a) and Express loans are included in the commercial category. During the second quarter of 2008, due to the depressed SBA loan sale market, we suspended the SBA loan sale operation and any remaining SBA loans held for sale were transferred into the regular portfolio at the lower of cost or fair value on the date of transfer.

The following table presents the balance of each major category of loans at the dates indicated:

	At June 30, 2009		At March 31, 2009		At June 30, 2008	
	Amount	% of total	Amount	% of total	Amount	% of total
			(Dollars in thousands)			
Loan Category:						
Domestic:						
Commercial	$ 776,060	20%	$ 779,971	20%	$ 833,376	21%
Real estate, construction	544,889	14	583,709	15	623,605	16
Real estate, mortgage	2,511,292	64	2,482,790	63	2,361,529	61
Consumer	35,150	1	38,615	1	47,500	1
Foreign:						
Commercial	42,672	1	44,955	1	46,096	1
Other, including real estate	1,722	(a)	2,126	(a)	1,861	(a)
Gross loans	3,911,785	100%	3,932,166	100%	3,913,967	100%
Less: unearned income	(7,419)		(7,881)		(8,911)	
Less: allowance for loan losses	(72,122)		(71,361)		(59,777)	
Total net loans	$3,832,244		$3,852,924		$3,845,279	

(a) Amount is less than 1%.

Although loans, net of unearned income, decreased $19.9 million during the second quarter of 2009, new loans and advances on existing loan commitments totaled $130.0 million.

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The following table presents our real estate mortgage loan portfolio.

Loan Category	Balance	Number of loans	Average loan balance
	At June 30, 2009		
	(Dollars in thousands)		
Commercial real estate mortgage:			
Owner-occupied	$ 372,828	435	$ 857
Retail	479,970	238	2,017
Office buildings	378,574	289	1,310
Industrial/warehouse	362,390	403	899
Hotels and other hospitality	284,980	66	4,318
Other	386,965	191	2,026
Total commercial real estate mortgage	2,265,707	1,622	1,397
Residential real estate mortgage:			
Multi-family	105,450	93	1,134
Single family owner-occupied	86,389	422	205
Single family nonowner-occupied	53,746	27	1,991
Total residential real estate mortgage	245,585	542	453
Total real estate mortgage	$2,511,292	2,164	$ 1,160

SBA 504 loans included in commercial real estate mortgage loans are as follows: $75.2 million in owner-occupied; $546,000 in retail; $4.1 million in office buildings; $7.3 million in industrial/warehouse; $15.4 million in hospitality; and $11.1 million in other.

Allowance for Credit Losses. The allowance for credit losses is the combination of the allowance for loan losses and the reserve for unfunded loan commitments. The allowance for loan losses is reported as a reduction of outstanding loan balances and the reserve for unfunded loan commitments is included within other liabilities. Generally, as loans are funded, the amount of the commitment reserve applicable to such funded loans is transferred from the reserve for unfunded loan commitments to the allowance for loan losses based on our reserving methodology. At June 30, 2009, the allowance for credit losses was comprised of the allowance for loan losses of $72.1 million and the reserve for unfunded loan commitments of $4.6 million.

An allowance for loan losses is maintained at a level deemed appropriate by management to adequately provide for known and inherent risks in the loan portfolio and other extensions of credit at the balance sheet date. The allowance is based upon a continuing review of the portfolio, past loan loss experience, current economic conditions which may affect the borrowers' ability to pay, and the underlying collateral value of the loans. Loans which are deemed to be uncollectible are charged off and deducted from the allowance. The provision for loan losses and recoveries on loans previously charged off are added to the allowance.

The methodology we use to estimate the amount of our allowance for credit losses is based on both objective and subjective criteria. While some criteria are formula driven, other criteria are subjective inputs included to capture environmental and general economic risk elements which may trigger losses in the loan portfolio, and to account for the varying levels of credit quality in the loan portfolios of the entities we have acquired that have not yet been captured in our objective loss factors.

Specifically, our allowance methodology contains four elements: (a) amounts based on specific evaluations of impaired loans; (b) amounts of estimated losses on several pools of loans categorized by type; (c) amounts of estimated losses for loans adversely classified based on our loan review process;

and (d) amounts for environmental and general economic factors that indicate probable losses were incurred but were not captured through the other elements of our allowance process.

Impaired loans are identified at each reporting date based on certain criteria and individually reviewed for impairment. A loan is considered impaired when it is probable that a creditor will be unable to collect all amounts due according to the original contractual terms of the loan agreement. We measure impairment of a loan based upon the fair value of the loan's collateral if the loan is collateral dependent or the present value of cash flows, discounted at the loan's effective interest rate, if the loan is not collateralized. The impairment amount on a collateralized loan is charged-off to the allowance and the impairment amount on a noncollateralized loan is set up as a specific reserve. Increased charge-offs generally result in increased provisions for credit losses.

Our loan portfolio, excluding impaired loans which are evaluated individually, is categorized into several pools for purposes of determining allowance amounts by loan pool. The loan pools we currently evaluate are: commercial real estate construction, residential real estate construction, SBA real estate, real estate other, commercial collateralized, commercial unsecured, SBA commercial, consumer, foreign, asset-based, and factoring. Within these loan pools, we then evaluate loans not adversely classified, which we refer to as "pass" credits, separately from adversely classified loans. The adversely classified loans are further grouped into three credit risk rating categories: special mention, substandard and doubtful. The allowance amounts for pass rated loans and those loans adversely classified, which are not reviewed individually, are determined using historical loss rates developed through migration analysis. The migration analysis is updated quarterly based on historic losses and movement of loans between ratings. As a result of this migration analysis and its quarterly updating, the increases we experienced in both chargeoffs and adverse classifications resulted in increased loss factors. In addition, beginning with the third quarter of 2008, we shortened the allowance methodology's accumulated net charge-off look-back data from 32 quarters to 16 quarters to allow greater emphasis on current charge-off activity. Such shortening also increased the loss factors.

Finally, in order to ensure our allowance methodology is incorporating recent trends and economic conditions, we apply environmental and general economic factors to our allowance methodology including: credit concentrations; delinquency trends; economic and business conditions; external factors such as fuel and building materials prices, the effects of adverse weather and hostilities; the quality of lending management and staff; lending policies and procedures; loss and recovery trends; nature and volume of the portfolio; nonaccrual and problem loan trends; usage trends of unfunded commitments; quality of loan review; and other adjustments for items not covered by other factors.

We recognize the determination of the allowance for loan losses is sensitive to the assigned credit risk ratings and inherent loss rates at any given point in time. Therefore, we perform sensitivity analyses to provide insight regarding the impact adverse changes in credit risk ratings may have on our allowance for loan losses. The sensitivity analyses has inherent limitations and is based on various assumptions as of a point in time and, accordingly, it is not necessarily representative of the impact loan risk rating changes may have on the allowance for loan losses. At June 30, 2009, in the event that 1 percent of our loans were downgraded one credit risk rating category for each category (e.g., 1 percent of the "pass" category moved to the "special mention" category, 1 percent of the "special mention" category moved to "substandard" category, and 1 percent of the "substandard" category moved to the "doubtful" category within our current allowance methodology), the allowance for loan losses would have increased by approximately $2.6 million. In the event that

5 percent of our loans were downgraded one credit risk category, the allowance for loan losses would increase by approximately $13.2 million. Given current processes employed by the Company, management believes the credit risk ratings and inherent loss rates currently assigned are appropriate. It is possible that others, given the same information, may at any point in time reach different conclusions that could be significant to the Company's financial statements. In addition, current credit risk ratings are subject to

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change as we continue to review loans within our portfolio and as our borrowers are impacted by economic trends within their market areas.

Management believes that the allowance for loan losses is adequate and appropriate for the known and inherent risks in our loan portfolio. In making its evaluation, management considers certain quantitative and qualitative factors including the Company's historical loss experience, the volume and type of lending conducted by the Company, the results of our credit review process, the amounts of classified, criticized and nonperforming assets, regulatory policies, general economic conditions, underlying collateral values, and other factors regarding collectibility and impairment. To the extent we experience, for example, increased levels of documentation deficiencies, adverse changes in collateral values, or negative changes in economic and business conditions which adversely affect our borrowers, our classified loans may increase. Higher levels of classified loans generally result in higher allowances for loan losses.

Management also believes that the reserve for unfunded loan commitments is adequate. In making this determination, we use the same methodology for the reserve for unfunded loan commitments as we do for the allowance for loan losses and consider the same quantitative and qualitative factors, as well as an estimate of the probability of advances of the commitments correlated to their credit risk rating.

The following table presents the changes in our allowance for credit losses for the periods indicated:

	As of or for the			
	Quarter Ended June 30, 2009	**Quarter Ended March 31, 2009**	**Year Ended December 31, 2008**	**Quarter Ended June 30, 2008**
	(Dollars in thousands)			
Balance at beginning of period	$ 76,632	$ 68,790	$ 61,028	$ 68,870
Provision for credit losses	18,000	14,000	45,800	3,500
Net charge-offs	(17,889)	(6,158)	(38,038)	(4,922)
Balance at end of period	$ 76,743	$ 76,632	$ 68,790	$ 67,448
Allowance for credit losses to loans, net of unearned income	1.97%	1.95%	1.72%	1.73%

The provisions for credit losses were based on our reserve methodology and considered, among other factors, net charge-offs, the level and trends of classified, criticized, and nonaccrual loans, general market conditions, the level and usage trends of unfunded commitments, and portfolio concentrations.

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The following table presents the changes in our allowance for loan losses for the periods indicated:

	As of or for the			
	Quarter Ended June 30, 2009	Quarter Ended March 31, 2009	Year Ended December 31, 2008	Quarter Ended June 30, 2008
	(Dollars in thousands)			
Balance at beginning of period	$ 71,361	$ 63,519	$ 52,557	$ 60,199
Loans charged off:				
Commercial	(3,405)	(1,881)	(7,664)	(3,420)
Real estate construction	(12,757)	(1,572)	(24,998)(a)	(1,417)
Real estate mortgage	(1,536)	(2,738)	(2,617)	(159)
Consumer	(529)	(216)	(3,947)	(97)
Foreign		(368)	(349)	(39)
Total loans charged off	(18,227)	(6,775)	(39,575)	(5,132)
Recoveries on loans charged off:				
Commercial	64	303	971	151
Real estate construction	2		88	
Real estate mortgage	231	190	412	46
Consumer	11	110	47	10
Foreign	30	14	19	3
Total recoveries on loans charged off	338	617	1,537	210
Net charge-offs	(17,889)	(6,158)	(38,038)	(4,922)
Provision for loan losses	18,650	14,000	49,000	4,500
Balance at end of period	$ 72,122	$ 71,361	$ 63,519	$ 59,777
Ratios:				
Allowance for loan losses to loans, net	1.85%	1.82%	1.59%	1.53%
Allowance for loan losses to nonaccrual loans	46.0%	51.5%	100.1%	93.2%
Annualized net charge-offs to average loans	1.83%	0.63%	0.96%	0.50%

(a) Includes $16.2 million related to the sale of $34.1 million of residential construction nonaccrual loans at a price of $17.9 million.

We recorded an $18.7 million provision for loan losses during the second quarter of 2009. Based on information currently available, management believes that the allowance for loan losses is adequate and appropriate for the known and inherent risks in our loan portfolio. In making its evaluation, management considers certain quantitative and qualitative factors including the Company's historical loss experience, the volume and type of lending conducted by the Company, the results of our credit review process, the amounts of classified, criticized and nonperforming assets, regulatory policies, general economic conditions, underlying collateral values, and other factors regarding collectibility and impairment.

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The following table presents the changes in our reserve for unfunded loan commitments for the periods indicated:

	As of or for the			
	Quarter Ended June 30, 2009	Quarter Ended March 31, 2009	Year Ended December 31, 2008	Quarter Ended June 30, 2008
	(Dollars in thousands)			
Balance at beginning of period	$ 5,271	$ 5,271	$ 8,471	$ 8,671
(Reversal) provision	(650)		(3,200)	(1,000)
Balance at end of period	$ 4,621	$ 5,271	$ 5,271	$ 7,671

The decline in the reserve for unfunded commitments in 2009 was due to lower commitment levels and lower usage. Lower commitment levels have resulted from a decline in lending activity. During the third quarter of 2008 we reviewed unfunded commitment usage for the last 16 quarters and noted that actual commitment usage in certain loan categories was consistently less than the estimated commitment usage factor built-in to our loss reserving methodology. Our methodology, once modified to reflect lower commitment usage factors, resulted in a $1.2 million reduction in the reserve for unfunded loan commitments during the third quarter of 2008.

Credit Quality. Our loan portfolio continues to experience pressure from the economic trends in Southern California as indicated by the level of net charge-offs and the increases in nonaccrual loans and nonperforming assets. We expect that such pressures will continue in 2009. The construction loan portfolio decreased $38.8 million during the second quarter of 2009 to $544.9 million at the end of June. Within our construction loan portfolio, we reduced our exposure to nonowner-occupied residential construction loans by $22.3 million during the second quarter of 2009. The reduction was due mostly to $14.6 million in payoffs and $4.6 million in foreclosures. Thirteen nonowner-occupied residential construction loans totaling approximately $63.9 million were on nonaccrual status at June 30, 2009. The details of the nonowner-occupied residential construction loan portfolio as of the dates indicated follows:

	As of June 30, 2009			As of March 31, 2009	As of December 31, 2008
Loan Category	Balance	Number of loans	Average loan balance	Balance	Balance
	(Dollars in thousands)				
Residential land acquisition and development	$ 53,552	19	$ 2,819	$ 58,420	$ 57,308
Residential nonowner-occupied single family	66,320	24	2,763	86,574	94,067
Unimproved residential land	48,169	12	4,014	48,814	50,163
Residential multifamily	40,798	8	5,100	37,341	32,184
	$ 208,839	63	$ 3,315	$ 231,149	$ 233,722

All nonaccrual and restructured loans are considered impaired and are evaluated individually for loss exposure. At June 30, 2009 we had $73.0 million of restructured loans of which $49.3 million were in compliance with the modified terms and on accrual status and with the remainder on nonaccrual status.

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The types of loans included in the nonaccrual category and accruing loans past due between 30 and 89 days as of June 30, 2009 and March 31, 2009 are presented below.

	Nonaccrual loans				Accruing and over 30 days past due	
	June 30, 2009		March 31, 2009			
Loan category	As a % of loan category	Balance	As a % of loan category	Balance	June 30, 2009 Balance	March 31, 2009 Balance
	(Dollars in thousands)					
SBA 504	5.3%	$ 6,497	3.2%	$ 3,869	$ 14,821	$ 2,699
SBA 7(a) and Express	24.6%	10,028	24.4%	10,173	529	738
Residential construction	35.6%	49,071	25.4%	44,778	2,606	22,893
Commercial real estate	1.0%	21,029	1.1%	22,782	7,087	13,442
Commercial construction	3.4%	8,606	5.7%	14,875	1,170	
Commercial	3.0%	21,760	2.5%	18,255	1,199	2,543
Commercial land	1.4%	1,058	1.9%	1,641		
Residential other	16.0%	20,504	15.5%	18,896	101	743
Residential land	23.4%	17,940	2.2%	1,257		
Residential multifamily	0.3%	301	0.3%	301		
Other, including foreign	0.2%	123	2.0%	1,670	40	640
	4.0%	$ 156,917	3.5%	$ 138,497	$ 27,553	$ 43,698

The $18.4 million net increase in nonaccrual loans during the second quarter is composed of additions of $57.5 million, repayments and payoffs of $5.6 million, charge-offs of $15.9 million, and foreclosures of $17.6 million. The most significant additions include: 4 high-end residential construction loan projects for $22.1 million, of which two are located in the Desert region of Southern California, one is located in the Inland Empire, and one is located in Orange County; a $4.9 million commercial real estate loan located in Orange County that was paid down significantly in early July; and two residential land loans for $17.0 million. The larger residential land loan ($13.1 million) is an 85 lot in-fill development loan in the South Bay area of Southern California. The second quarter increase in nonaccrual loans also includes 3 SBA real estate loans totaling $2.7 million, $2.0 million in SBA commercial loans, 2 financing receivables totaling $2.1 million and 3 loans in the residential other category totaling $1.6 million.

In addition to the loans added to nonaccrual in the second quarter, the most significant nonaccrual loans include: a $16.6 million residential construction loan collateralized by 28 unsold units of a 32-unit condo project in Orange County; a $13.7 million commercial loan for a retailer of high-end sports equipment where we continue to work with the bankrupt debtor and the guarantor; and an $11.8 million "residential other" loan secured by several exclusive residential properties in and around San Diego.

Included in the nonaccrual loans at the end of June are $16.5 million of SBA related loans representing 10.5% of total nonaccrual loans at that date. The SBA 504 loans are secured by first trust deeds on owner-occupied business real estate with loan-to-value ratios of generally 50% or less at the time of origination. SBA 7(a) loans are secured by borrowers' real estate and/or business assets and are covered by an SBA guarantee of up to 85% of the loan amount. The SBA guaranteed portion on the 7(a) and Express loans shown above is $8.1 million. At June 30, 2009, the SBA loan portfolio totaled $165.0 million and was composed of $124.1 million in SBA 504 loans and $40.9 million in SBA 7(a) and Express loans.

Loans accruing and over 30 days past due decreased $16.1 million during the second quarter to $27.6 million due mostly to 21 loans totaling $15.3 million that were brought current and a $1.0 million combination of writeoffs, payoffs and transfers.

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Nonperforming assets include nonaccrual loans and OREO and totaled $203.5 million at the end of June compared to $186.2 million at the end of March. The ratio of nonperforming assets to loans and OREO increased to 5.15% at June 30, 2009 from 4.69% at March 31, 2009. The increase in nonperforming assets is due to higher nonaccrual loans.

The activity in OREO during the second quarter of 2009 included 14 sales for $13.3 million; write-downs of $7.2 million and 11 additions of $19.5 million. The write-downs were based on new appraisals or negotiated sales prices with buyers. The following table presents the components of OREO by property type as of the dates indicated:

	Balance as of	
Property Type	**June 30, 2009**	**March 31, 2009**
	(Dollars in thousands)	
Improved residential land	$ 2,611	$ 4,271
Commercial real estate	28,022	31,003
Residential condominiums	2,418	3,143
Single family residences	13,532	9,256
Total	$ 46,583	$ 47,673

The following table presents historical credit quality information as of the dates indicated:

		As of or for the	
	Quarter Ended June 30, 2009	**Year Ended December 31, 2008**	**Quarter Ended June 30, 2008**
		(Dollars in thousands)	
ALLOWANCE FOR CREDIT LOSSES:			
Allowance for loan losses	$ 72,122	$ 63,519	$ 59,777
Reserve for unfunded loan commitments	4,621	5,271	7,671
Allowance for credit losses	$ 76,743	$ 68,790	$ 67,448
NONPERFORMING ASSETS:			
Nonaccrual loans	$ 156,917	$ 63,470	$ 64,116
Other real estate owned	46,583	41,310	9,886
Total nonperforming assets	$ 203,500	$ 104,780	$ 74,002
Allowance for credit losses to loans, net of unearned income	1.97%	1.72%	1.73%
Allowance for credit losses to nonaccrual loans	48.9%	108.4%	105.2%
Allowance for credit losses to nonperforming assets	37.7%	65.7%	91.1%

Loan Portfolio Risk Elements. There has been an increasing trend in the level of nonaccrual loans due to the economy and its effect on our borrowers. Certain industries and collateral types have been more affected than others.

We have $246.9 million of commercial real estate mortgage loans maturing over the next 12 months. In the event we refinance any of these loans because the borrowers are unable to obtain financing elsewhere due to the inability of banks in our market area to make loans, such loans may be considered troubled debt restructurings even though they were performing throughout their terms. Higher levels of troubled debt restructurings may lead to increased classified assets and credit loss provisions.

The hospitality industry is being adversely impacted by the economic downturn. The continued reductions in recreational and business travel have caused declines in occupancy and average daily room rates. At June 30, 2009, we have $285.0 million of hotel and other hospitality related commercial

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real estate loans. None of these loans were on nonaccrual status at June 30, 2009. Subsequently, however, we moved 2 loans totaling $6.3 million to nonaccrual status.

Subsequent to June 30, 2009, we moved loans totaling $43.8 million to nonaccrual status, including the two hospitality loans mentioned above. Repayments on nonaccrual loans totaled $5.0 million. The additions include a $23.5 million relationship secured by a golf course, three related residential units and 15 improved lots located in the Desert region of Southern California. We do not expect any losses on this relationship based on the collateral value and ongoing negotiations with the borrower. The classification of loans as nonaccrual during the quarter and subsequent to quarter-end was in accordance with our policy which requires a loan to be placed on nonaccrual status when the principal or interest payments are past due 90 days or when, in the opinion of management, there is reasonable doubt as to the collectibility in the normal course of business.

Deposits. The following table presents the balance of each major category of deposits at the dates indicated:

	At June 30, 2009		**At March 31, 2009**		**At June 30, 2008**	
	Amount	**% of total**	**Amount**	**% of total**	**Amount**	**% of total**
	(Dollars in thousands)					
Noninterest-bearing	$1,227,891	38%	$1,223,884	36%	$1,239,098	39%
Interest-bearing:						
Interest checking	366,126	11	359,551	11	355,754	11
Money market accounts	897,152	28	890,558	26	1,050,726	33
Savings	109,910	3	116,550	3	100,422	3
Time deposits under $100,000	250,826	8	400,084	12	207,621	7
Time deposits over $100,000	401,406	12	410,189	12	238,592	7
Total interest-bearing	2,025,420	62	2,176,932	64	1,953,115	61
Total deposits	$3,253,311	100%	$3,400,816	100%	$3,192,213	100%

Total deposits decreased $147.5 million during the second quarter. When brokered and acquired money desk deposits are excluded, however, deposits decreased by only $11.9 million; this includes a $10.5 million increase in our core deposits (noninterest-bearing demand, interest-bearing checking, savings and money market deposits). At June 30, 2009, noninterest-bearing demand deposits totaled $1.2 billion and represented 38% of total deposits. Brokered and acquired money desk deposits totaled $31.8 million at June 30, 2009 compared to $167.4 million at March 31, 2009. Since year end core deposits have increased $130.9 million. Deposits by foreign customers, primarily located in Mexico and Canada, totaled $103.1 million, or approximately 3.17% of total deposits at June 30, 2009.

Regulatory Matters

The regulatory capital guidelines and the actual capital ratios for Pacific Western and the Company as of June 30, 2009, are as follows:

	Minimum Regulatory Requirements	Actual	
	Well Capitalized	Pacific Western	Company Consolidated
Tier 1 leverage capital ratio	5.00%	11.04%	12.78%
Tier 1 risk-based capital ratio	6.00%	11.45%	13.26%
Total risk-based capital	10.00%	12.71%	14.52%
Tangible common equity ratio		10.71%	9.65%

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The Company issued subordinated debentures to trusts that were established by us or entities we have acquired, which, in turn, issued trust preferred securities, which totaled $123.0 million at June 30, 2009. Our trust preferred securities are currently included in our Tier I capital for purposes of determining the Company's Tier I and total risk-based capital ratios. The FRB, which is the holding company's banking regulator, has promulgated a modification of the capital regulations affecting trust preferred securities. Although this modification was scheduled to be effective on March 31, 2009, the Federal Reserve postponed the effective date to March 31, 2011. At that time, the Company will be allowed to include in Tier I capital an amount of trust preferred securities equal to no more than 25% of the sum of all core capital elements, which is generally defined as shareholders' equity, less goodwill net of any related deferred income tax liability. The regulations currently in effect through December 31, 2010 limit the amount of trust preferred securities that can be included in Tier I capital to 25% of the sum of core capital elements without a deduction for goodwill. We have determined that our Tier I capital ratios would remain above the well-capitalized level had the modification of the capital regulations been in effect at June 30, 2009. We expect that our Tier I capital ratios will be at or above the existing well capitalized levels on March 31, 2011, the second date on which the modified capital regulations must be applied.

Tangible common equity is a non-GAAP financial measure used by investors, analysts, and bank regulatory agencies. Tangible common equity includes total equity, less any preferred equity, goodwill and intangible assets. The methodology of determining tangible common equity may differ among companies. Management reviews tangible common equity along with other measures of capital on a regular basis and has included this non-GAAP financial information, and the corresponding reconciliation to total equity, because of current interest in such information on the part of market participants.

As announced on January 14, 2009, we issued in a private placement to CapGen Capital Group II LP 3,846,153 PacWest common shares at $26.00 per share for total cash consideration of approximately $100 million.

On June 16, 2009, PacWest Bancorp filed a registration statement with the SEC to offer to sell, from time to time, shares of common stock, preferred stock, and other equity-linked securities, for an aggregate initial offering price of up to $150 million. The registration statement was declared effective on June 30, 2009. Proceeds from the offering are anticipated to be used to fund future acquisitions of banks and financial institutions and for general corporate purposes. To date, no shares have been offered under this registration statement.

Liquidity Management

Liquidity. The goals of our liquidity management are to ensure the ability of the Company to meet its financial commitments when contractually due and to respond to other demands for funds such as the ability to meet the cash flow requirements of customers who may be either depositors wanting to withdraw funds or borrowers who may need assurance that sufficient funds will be available to meet their credit needs. We have an Executive Asset/Liability Management Committee, or Executive ALM Committee, which is comprised of members of senior management and responsible for managing balance sheet and off-balance sheet commitments to meet the needs of customers while achieving our financial objectives. Our Executive ALM Committee meets regularly to review funding capacities, current and forecasted loan demand, and investment opportunities.

Historically, the Bank's primary liquidity source has been its core deposit base. Over the last several years the Bank's reliance on collateralized FHLB advances has increased as one of its sources of affordable and immediately available liquidity. The level of such wholesale funding is monitored based on the Bank's liquidity requirements, and we maintain what we believe to be an acceptable level of this collateralized borrowing capacity. The Bank's secured borrowing capacity with the FHLB was

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$954.5 million, of which $367.3 million was available as of June 30, 2009. The Bank also maintains a security repurchase line with the FHLB to provide an additional $111.9 million in secured borrowing capacity, against which there were no borrowings as of June 30, 2009. In addition to the secured borrowing relationship with the FHLB, and to meet short term liquidity needs, the Bank maintains adequate balances in liquid assets, which include cash and due from banks, Federal Funds sold, interest bearing deposits in other financial institutions, and unpledged investment securities available-for-sale. The Bank also established a secured line of credit with the FRB in 2008 which had a borrowing capacity of $485.9 million at June 30, 2009 and no amounts were outstanding under this line on that date. In addition to its secured lines of credit the Bank also maintains unsecured lines of credit, subject to availability, of $155.0 million with correspondent banks for purchase of overnight funds.

The recent disruption in the financial credit and liquidity markets has had the effect of decreasing overall liquidity in the marketplace. While we have experienced net deposit outflows, we have augmented our funding needs with collateralized FHLB borrowings and large denomination time deposits. At June 30, 2009, the Bank had $22.3 million of these large denomination time deposits, the availability of which is uncertain and subject to competitive market forces. In addition, we have $96.7 million of customer deposits that were subsequently participated with other FDIC insured financial institutions through the CDARS program as a means to provide FDIC deposit insurance coverage for the full amount of our participating customers' deposits.

The primary sources of liquidity for the Company, on a stand alone basis, include the dividends from the Bank and our ability to raise capital, issue subordinated debt and secure outside borrowings. The ability of the Company to obtain funds for the payment of dividends to our stockholders and for other cash requirements is largely dependent upon the Bank's earnings. Pacific Western is subject to restrictions under certain federal and state laws and regulations which limit its ability to transfer funds to the Company through intercompany loans, advances or cash dividends. Dividends paid by state banks, such as Pacific Western, are regulated by the DFI under its general supervisory authority as it relates to a bank's capital requirements. A state bank may declare a dividend without the approval of the DFI as long as the total dividends declared in a calendar year do not exceed either the retained earnings or the total of net profits for three previous fiscal years less any dividends paid during such period. During the second quarter of 2009, PacWest received no dividends from the Bank. For the foreseeable future, further dividends from the Bank to the Company require DFI approval.

At June 30, 2009, the Company had, on a stand alone basis, approximately $79.2 million in cash on deposit at the Bank. We believe we have adequate sources of liquidity to fund operations.

Contractual Obligations. The known contractual obligations of the Company at June 30, 2009, are as follows:

	At June 30, 2009 and Due				
	Within One Year	One to Three Years	Three to Five Years	After Five Years	Total
	(Dollars in thousands)				
Short-term debt obligations	$310,000	$	$	$	$310,000
Brokered deposits	22,193	100			22,293

Long-term debt obligations			50,000	354,897	404,897
Operating lease obligations	13,783	23,971	16,229	18,878	72,861
Other contractual obligations	3,615	4,136			7,751
Total	$349,591	$ 28,207	$66,229	$373,775	$817,802

The amount of brokered deposits included in the contractual obligations table represents wholesale broker deposits only. Such amount does not include $96.7 million of customer deposits that were subsequently participated with other FDIC insured financial institutions as a means to provide FDIC deposit insurance coverage for the full amount of our customers' deposits.

Long term debt obligations include $275 million of callable FHLB advances which may be called by the FHLB on various call dates. While the FHLB may call the advances to be repaid for any reason, they are likely to be called if market interest rates are higher than the advances' stated rates on the call dates. If the advances are called by the FHLB, there is no prepayment penalty. Should our FHLB advances be called, we would evaluate the funding opportunities available at that time, including new secured FHLB borrowings at the prevailing market rates. As borrowing rates are currently lower than our contract rates, we do not expect our secured FHLB borrowings to be called. Debt obligations are also discussed in Note 5 of Notes to Unaudited Condensed Consolidated Financial Statements contained in "Item 1. Unaudited Consolidated Financial Statements." Operating lease obligations are discussed in the Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2008. The other contractual obligations relate to the minimum liability associated with our data and item processing contract with a third-party provider.

We believe that we will be able to meet our contractual obligations as they come due through the maintenance of adequate cash levels. We expect to maintain adequate cash levels through profitability, loan and securities repayment and maturity activity, and continued deposit gathering activities. We believe we have in place sufficient borrowing mechanisms for short-term liquidity needs.

Off-Balance Sheet Arrangements

Our obligations also include off-balance sheet arrangements consisting of loan-related commitments, of which only a portion are expected to be funded. At June 30, 2009, our loan-related commitments, including standby letters of credit, totaled $875.8 million. The commitments which result in a funded loan increase our profitability through net interest income. We manage our overall liquidity taking into consideration funded and unfunded commitments as a percentage of our liquidity sources. Our liquidity sources have been and are expected to be sufficient to meet the cash requirements of our lending activities.

Asset/Liability Management and Interest Rate Sensitivity

Interest Rate Risk. Our market risk arises primarily from credit risk and interest rate risk inherent in our lending and financing activities. To manage our credit risk, we rely on adherence to our underwriting standards and loan policies, internal loan monitoring and periodic credit review as well as our allowance for credit losses methodology, all of which are administered by the Bank's Credit Administration Group and overseen by the Company's Credit Risk Committee. To manage our exposure to changes in interest rates, we perform asset and liability management activities which are governed by guidelines pre-established by our Executive ALM Committee, and approved by our Asset/Liability Management Committee of the Board of Directors, which we refer to as our Board ALCO. Our Executive ALM Committee monitors our compliance with our asset/liability policies. These policies focus on providing sufficient levels of net interest income while considering acceptable levels of interest rate exposure as well as liquidity and capital constraints.

Market risk sensitive instruments are generally defined as derivatives and other financial instruments, which include investment securities, loans, deposits, and borrowings. At June 30, 2009, we had not used any derivatives to alter our interest rate risk profile or for any other reason. However, both the repricing characteristics of our fixed rate loans and floating rate loans, the significant percentage of noninterest bearing deposits compared to interest earning assets, and the callable features in certain borrowings, may influence our interest rate risk profile. Our financial instruments include loans receivable, Federal funds sold, interest bearing deposits in financial institutions, Federal Home Loan Bank stock, investment securities, deposits, borrowings and subordinated debentures.

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We measure our interest rate risk position on at least a quarterly basis using three methods: (i) net interest income simulation analysis; (ii) market value of equity modeling; and (iii) traditional gap analysis. The results of these analyses are reviewed by the Executive ALM Committee and the Board ALCO quarterly. If hypothetical changes to interest rates cause changes to our simulated net present value of equity and/or net interest income outside of our pre-established limits, we may adjust our asset and liability mix in an effort to bring our interest rate risk exposure within our established limits.

We evaluated the results of our net interest income simulation and market value of equity models prepared as of June 30, 2009, the results of which are presented below. Our net interest income simulation indicates that our balance sheet is liability sensitive as rising interest rates would result in a decline in our net interest margin. This profile is primarily a result of the increased origination of fixed rate loans and variable rate loans with initial fixed rate terms, which is driven by customer demand for fixed rate products in this low interest rate environment. Our market value of equity model indicates an asset sensitive profile suggesting a sudden sustained increase in rates would result in an increase in our estimated market value of equity. This profile is a result of the assumed floors in the Company's offering rates which are not expected to increase to the extent of the movement of market interest rates, and the significant value placed on the Company's noninterest bearing deposits for purposes of this analysis. The divergent profile between the net interest income simulation and market value of equity model is a result of the Company's significant level of noninterest bearing deposits. Static balances of noninterest bearing deposits do not impact the net interest income simulation. However, the value of these deposits increase substantially in the market value of equity model when market rates are assumed to rise. In general, we view the net interest income model results as more relevant to the Company's current operating profile and manage our balance sheet based on this information.

Net interest income simulation. We used a simulation model to measure the estimated changes in net interest income that would result over the next 12 months from immediate and sustained changes in interest rates as of June 30, 2009. This model is an interest rate risk management tool and the results are not necessarily an indication of our future net interest income. This model has inherent limitations and these results are based on a given set of rate changes and assumptions at one point in time. We have assumed no growth in either our interest sensitive assets or liabilities over the next 12 months; therefore, the results reflect an interest rate shock to a static balance sheet.

This analysis calculates the difference between net interest income forecasted using both increasing and declining interest rate scenarios and net interest income forecasted using a base market interest rate derived from the treasury yield curve at June 30, 2009. In order to arrive at the base case, we extend our balance sheet at June 30, 2009 one year and reprice any assets and liabilities that would be expected to reprice or mature during that period based on contractual obligations and projected prepayment behavior. Using the products' pricing as of June 30, 2009, we calculated an estimated net interest income and net interest margin. The effects of certain balance sheet attributes, such as fixed-rate loans, floating rate loans that have reached their floors and the volume of noninterest bearing deposits as a percentage of earning assets, impact our assumptions and consequently the results of our interest rate risk management model. Changes that may vary significantly from our assumptions include loan and deposit growth or contraction, changes in the mix of our earning assets or funding sources, and future asset/liability management decisions, all of which may have significant effects on our net interest income.

The net interest income simulation model includes various assumptions regarding the repricing relationship for each of our assets and liabilities. Many of our assets are floating rate loans, which are assumed to reprice to the same extent as the change in market rates according to their contracted index. However, floating rate loans tied to our base lending rate are assumed to reprice upward only after the second 75 basis point increase in market rates. This assumption is due to the fact we reduced our base lending rate 100 basis points when the Federal Reserve lowered the Federal Funds benchmark rate by 175 basis points. Some loans and investment vehicles include the opportunity of prepayment (imbedded options) and the simulation model uses national indexes to estimate these prepayments and reinvest these proceeds at current simulated yields. Our deposit products reprice at our discretion and are assumed to reprice more slowly in a rising or declining interest rate environment, usually repricing less than the change in market rates. Also, a callable option feature on certain borrowings will reprice differently in a rising interest rate environment than in a declining interest rate environment.

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The simulation analysis does not account for all factors that impact this analysis, including changes by management to mitigate the impact of interest rate changes or the impact a change in interest rates may have on our credit risk profile, loan prepayment estimates and spread relationships which can change regularly. In addition, the simulation analysis does not make any assumptions regarding loan fee income, which is a component of our net interest income and tends to increase our net interest margin. In the six months ending June 30, 2009, loan fee income increased our net interest margin by 16 basis points. Management reviews the model assumptions for reasonableness on a quarterly basis.

The following table presents as of June 30, 2009, forecasted net interest income and net interest margin for the next 12 months using a base case and the estimated change to the base scenario given immediate and sustained upward and downward movements in interest rates of 100, 200 and 300 basis points.

Interest rate scenario	Estimated Net Interest Income	Percentage Change From Base	Estimated Net Interest Margin	Estimated Net Interest Margin Change From Base
	(Dollars in thousands)			
Up 300 basis points	$ 198,615	(6.42)%	4.75%	(0.33)%
Up 200 basis points	$ 197,397	(6.99)%	4.72%	(0.35)%
Up 100 basis points	$ 200,825	(5.38)%	4.80%	(0.27)%
BASE CASE	$ 212,236		5.07%	
Down 100 basis points	$ 215,175	1.38%	5.14%	0.07%
Down 200 basis points	$ 214,453	1.04%	5.13%	0.05%
Down 300 basis points	$ 214,023	0.84%	5.12%	0.04%

Our net interest income simulation model prepared as of June 30, 2009 suggests our balance sheet is liability sensitive. Liability sensitivity suggests that in a rising interest rate environment, our net interest margin would decrease; and during a falling or sustained low interest rate environment, our net interest margin would increase. This liability sensitive profile is due to the assumed repricing characteristics of our loans, deposits and borrowings. The Federal Reserve lowered the Federal Funds benchmark rate by 175 basis points during the fourth quarter of 2008 and we reduced our base lending rate 100 basis points. While not lowering our base lending rate may prevent further compression of our net interest margin given the current low interest rate environment, our loans will act like fixed rate instruments until market rates catch up to our loan offering rates. Accordingly, in the event of a sudden sustained increase in rates we assume the cost of our liabilities would begin to increase immediately while our loans are assumed to reprice upward only after market rates exceed our interest rate floors. This would have the effect of compressing our net interest margin as approximately 34% of our loans have interest rates that are tied to our base lending rate and are subject to repricing. In addition, 20% of our loans are tied to an index other than our base lending rate and are also considered to be floating rate loans. Although, our floating rate loans may reprice during the life of the loan, they are subject to other terms and the repricing effect may not be immediate and to the extent of the movement in the index rate.

In comparing the June 30, 2009, simulation results to March 31, 2009, we have become more liability sensitive. The increase in our liability sensitivity is due mostly to increases in overnight borrowings from the FHLB which will reprice immediately following changes in interest rates.

Market value of equity. We measure the impact of market interest rate changes on the net present value of estimated cash flows from our assets, liabilities and off-balance sheet items, defined as the market value of equity, using a simulation model. This simulation model assesses the changes in the market value of our interest sensitive financial instruments that would occur in response to an instantaneous and sustained increase or decrease in market interest rates of 100, 200 and 300 basis points. This analysis assigns significant value to our noninterest bearing deposit balances. The projections are by their nature forward looking and therefore inherently uncertain, and include various assumptions regarding cash flows and interest rates. This model is an interest rate risk management tool and the results are not necessarily an indication of our actual future results. Actual results may vary significantly from the results suggested by the market value of equity table. Loan prepayments and deposit attrition, changes in the mix of our earning assets or funding sources, and future asset/liability management decisions, among others, may vary significantly from our assumptions.

The base case is determined by applying various current market discount rates to the estimated cash flows from the different types of assets, liabilities and off-balance sheet items existing at June 30, 2009. The following table shows the projected change in the market value of equity for the set of rate shocks presented as of June 30, 2009:

Interest rate scenario	Estimated Market Value	Percentage Change From Base	Percentage of total assets	Ratio of Estimated Market Value to Book Value
	(Dollars in thousands)			
Up 300 basis points	$ 670,247	10.17%	15.0%	144.4%
Up 200 basis points	$ 692,038	13.75%	15.5%	149.1%
Up 100 basis points	$ 662,478	8.90%	14.8%	142.7%
BASE CASE	$ 608,360		13.6%	131.1%
Down 100 basis points	$ 555,240	(8.73)%	12.4%	119.6%
Down 200 basis points	$ 496,171	(18.44)%	11.1%	106.9%
Down 300 basis points	$ 447,814	(26.39)%	10.0%	96.5%

The results of our market value of equity model indicate an asset sensitive interest rate risk profile at June 30, 2009 demonstrated by the increase in the market value of equity in the "up" interest rate scenarios compared to the "base case". Given the historically low market interest rates as of June 30, 2009, the "down" scenarios at June 30, 2009 are not considered meaningful and excluded from the following discussion.

The discount rate used to value our loan portfolio is derived from the expected offering rate for each loan type with a similar term and credit risk profile. In this type of analysis, a higher discount rate applied to a loan portfolio will result in a lower loan value. Given the current interest rate environment management has placed floors on the Company's offering rates, including the assumption that our base lending rate will not increase until after a 75 basis point increase in market rates. Accordingly, in the increasing rate scenarios our offering rates (the discount rates) are not expected to increase to the same extent as market rates and in turn our loans are not projected to decline in value to the same extent as they would have without the floors. The discount rates for our liabilities are expected to increase to the same extent as increases in market rates. Therefore our liabilities are expected increase in value as rates rise thereby increasing the estimated market value of equity in the rising rate scenarios.

In comparing the June 30, 2009, simulation results to March 31, 2009, we have become less asset sensitive. The decrease in our asset sensitivity is due mostly to a steepening of the yield curve since March 31, 2009. The steeper yield curve results in a higher discount rate in the increasing rate scenarios, once the assumed rates rise above the loan floors, thereby lowering the value of our loans and asset sensitivity for purposes of this analysis.

Gap analysis. As part of the interest rate management process, we use a gap analysis. A gap analysis provides information about the volume and repricing characteristics and relationship between the amounts of interest-sensitive assets and interest-bearing liabilities at a particular point in time. An effective interest rate strategy attempts to match the volume of interest sensitive assets and interest

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bearing liabilities repricing over different time intervals. The following table illustrates the volume and repricing characteristics of our balance sheet at June 30, 2009 over the indicated time intervals:

Interest Rate Sensitivity
At June 30, 2009
Amounts Maturing or Repricing In

	3 Months Or Less	Over 3 Months to 12 Months	Over 1 Year to 5 Years	Over 5 Years	Non Interest Rate Sensitive	Total
			(Dollars in thousands)			
ASSETS						
Cash and deposits in financial institutions	$ 79,314	$	$	$	$ 102,351	$ 181,665
Federal funds sold						
Investment securities	6,024	13,775	6,975	172,294		199,068
Loans, net of unearned income	1,713,347	212,508	925,040	1,053,471		3,904,366
Other assets					191,137	191,137
Total assets	$1,798,685	$ 226,283	$ 932,015	$1,225,765	$ 293,488	$4,476,236
LIABILITIES AND STOCKHOLDERS' EQUITY						
Noninterest-bearing demand deposits	$	$	$	$	$ 1,227,891	$1,227,891
Interest-bearing demand, money market and savings	1,373,188					1,373,188
Time deposits	318,122	294,466	39,644			652,232
Borrowings	135,000	175,000	50,000	225,000		585,000
Subordinated debentures	87,631		20,619	18,558	3,089	129,897
Other liabilities					43,931	43,931
stockholders' equity					464,097	464,097
Total liabilities and stockholders' equity	$1,913,941	$ 469,466	$ 110,263	$ 243,558	$ 1,739,008	$4,476,236
Period gap	$ (115,256)	$ (243,183)	$ 821,752	$ 982,207	$(1,445,520)	
	$1,798,685	$2,024,968	$2,956,983	$4,182,748		

Cumulative interest-earning assets				
Cumulative interest-bearing liabilities	$1,913,941	$2,383,407	$2,493,670	$2,737,228
Cumulative gap	$ (115,256)	$ (358,439)	$ 463,313	$1,445,520
Cumulative interest-earning assets to cumulative				
interest-bearing liabilities	94.0%	85.0%	118.6%	152.8%
Cumulative gap as a percent of:				
Total assets	(2.6)%	(8.0)%	10.4%	32.3%
Interest earning assets	(2.8)%	(8.7)%	11.3%	35.2%

All amounts are reported at their contractual maturity or repricing periods, except for $33.8 million in FHLB stock which is shown as a longer-term investment because of previously announced dividend and stock redemption suspensions. This analysis makes certain assumptions as to interest rate sensitivity of savings and NOW accounts which have no stated maturity and have had very little rate fluctuation in the past three years. Money market accounts are repriced at management's discretion and generally are more rate sensitive.

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The preceding table indicates that we had a negative one year cumulative gap of $358.4 million at June 30, 2009, a similar profile compared to March 31, 2009 and a decrease of $46.1 million from the negative gap position of $404.5 million at December 31, 2008. The decrease in the negative gap is the result of a decrease in time deposits. This gap position suggests that we are liability sensitive and if rates were to increase, our net interest margin would most likely decrease. Conversely, if rates were to decrease, our net interest margin would most likely increase. The ratio of interest-earning assets to interest-bearing liabilities maturing or repricing within one year at June 30, 2009 is 85.0%. This one year gap position indicates that interest expense is likely to be affected to a greater extent than interest income for any changes in interest rates within one year from June 30, 2009.

Borrowings includes three term advances totaling $275 million with maturity dates of 2013 or later which contain quarterly call options and may be called by the FHLB on various call dates as detailed in Note 5 of Notes to Unaudited Condensed Consolidated Financial Statements contained in "Item 1. Unaudited Condensed Consolidated Financial Statements." While the FHLB may call the advances to be repaid for any reason, they are likely to be called if market interest rates are higher than the advances' stated rates on the call dates. If the advances are called by the FHLB, there is no prepayment penalty. Should our FHLB advances be called, we would evaluate the funding opportunities available at that time, including new secured borrowings from the FHLB at the then market rates. As borrowing rates are currently lower than our contract rates, we do not expect our secured FHLB borrowings to be called. We may repay the advances with a prepayment penalty at any time.

The gap table has inherent limitations and actual results may vary significantly from the results suggested by the gap table. The gap table assumes a static balance sheet, as does the net interest income simulation, and, accordingly, looks at the repricing of existing assets and liabilities without consideration of new loans and deposits that reflect a more current interest rate environment. Unlike the net interest income simulation, however, the interest rate risk profile of certain deposit products and floating rate loans that have reached their floors cannot be captured effectively in a gap table. Although the table shows the amount of certain assets and liabilities scheduled to reprice in a given time frame, it does not reflect when or to what extent such repricings may actually occur. For example, interest-bearing demand, money market and savings deposits are shown to reprice in the second three months, but we may choose to reprice these deposits more slowly and incorporate only a portion of the movement in market rates based on market conditions at that time. Alternatively, a loan which has reached its floor may not reprice despite a change in market interest rates causing such loan to act like a fixed rate loan regardless of its scheduled repricing date. For example, a loan already at its floor would not reprice if the adjusted rate was less than its floor. The gap table as presented is not able to factor in the flexibility we believe we have in repricing either deposits or the floors on our loans.

We believe the estimated effect of a change in interest rates is better reflected in our net interest income and market value of equity simulations which incorporate many of the factors mentioned.

ITEM 3. Quantitative and Qualitative Disclosure about Market Risk

Please see the section above titled "Asset/Liability Management and Interest Rate Sensitivity" in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" which provides an update to our quantitative and qualitative disclosure about market risk. This analysis should be read in conjunction with text under the caption "Quantitative and Qualitative Disclosure About Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2008, which text is incorporated herein by reference. Our analysis of market risk and market-sensitive financial information contains forward-looking statements and is subject to the disclosure at the beginning of Item 2 regarding such forward-looking information.

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ITEM 4. Controls and Procedures

As of the end of the period covered by this report, an evaluation was carried out by the Company's management, with the participation of the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period covered by this report, these disclosure controls and procedures were effective.

There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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PART II OTHER INFORMATION

ITEM 1. Legal Proceedings

In the ordinary course of our business, we are party to various legal actions, which we believe are incidental to the operation of our business. Although the ultimate outcome and amount of liability, if any, with respect to these legal actions to which we are currently a party cannot presently be ascertained with certainty, in the opinion of management, based upon information currently available to us, any resulting liability is not likely to have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

ITEM 1A. Risk Factors

There have been no material changes with respect to the risk factors described in Item 1A. to Part I of our Annual Report on Form 10-K for the fiscal year ended December 31, 2008, which Item 1A. is incorporated herein by reference.

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

(c) Issuer Repurchases of Common Stock

The following table presents stock purchases made during the second quarter of 2009:

	Total Shares Purchased(a)	Average Price Per Share
April 1 - April 30, 2009		
May 1 - May 31, 2009	4,827	$ 17.27
June 1 - June 30, 2009		
Total	4,827	$ 17.27

(a) Shares repurchased in satisfaction for financial obligations incurred through the vesting of the Company's restricted stock .

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ITEM 4. Submission of Matters to a Vote of Security Holders

I.

(a) The Company held its Annual Meeting of Stockholders on May 12, 2009.

(b)

All of the Company's non-retiring directors were re-elected. The list of directors nominated and elected is included in response to Item 4(c) below.

(c)

At the annual meeting, stockholders voted on: (1) the election of the Company's directors; and (2) an amendment and restatement of the Company's 2003 Stock Incentive Plan to increase the aggregate number of shares available for issuance under the plan from 3,500,000 to 5,000,000, and to extend the expiration date of the plan from April 17, 2010 to May 31, 2015. All nominees for director were elected and the other measure was approved. The results of the voting were as follows:

Matter	Votes For	Withheld
Election of Directors:		
Mark N. Baker	26,505,380	2,049,513
Stephen M. Dunn	19,300,866	9,254,027
John M. Eggemeyer	25,899,012	2,655,881
Barry C. Fitzpatrick	19,300,679	9,254,214
George E. Langley	26,599,829	1,955,064
Susan E. Lester	26,487,410	2,067,483
Timothy B. Matz	18,822,205	9,732,688
Arnold W. Messer	19,299,959	9,254,934
Daniel B. Platt	26,487,911	2,066,982
John W. Rose	27,888,853	666,040
Robert A. Stine	26,499,239	2,055,654
Matthew P. Wagner	26,609,311	1,945,582

Matter	Votes For	Votes Against	Abstentions	Broker Non-Votes
To increase the authorized number of shares available for issuance under PacWest's 2003 Stock Incentive Plan from 3,500,000 to 5,000,000, and to extend the expiration date of the plan from April 17, 2010 to May 31, 2015	13,249,053	10,732,061	184,509	4,389,270

ITEM 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Incorporation, as amended, of PacWest Bancorp, a Delaware corporation (Exhibit 3.1 to Form 8-K filed on May 14, 2008 and incorporated herein by this reference).
3.2	Bylaws of PacWest Bancorp, a Delaware corporation, dated April 22, 2008 (Exhibit 3.2 to Form 8-K filed on May 14, 2008 and incorporated herein by this reference).

31.1 Rule 13a-14(a) / 15d-14(a) Certification of Chief Executive Officer.
31.2 Rule 13a-14(a) / 15d-14(a) Certification of Chief Financial Officer.
32.1 Section 1350 Certification of Chief Executive Officer.
32.2 Section 1350 Certification of Chief Financial Officer.

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SIGNATURES

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

PACWEST BANCORP

Date: August 7, 2009	/s/ VICTOR R. SANTORO
	Victor R. Santoro *Executive Vice President and Chief Financial Officer*