NORSK HYDRO A S A
Form 20-F
June 30, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 20-F

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

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

For The Fiscal Year Ended December 31, 2003

OR

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

For the transition period from ___________________ to ___________________

Commission file number: 1-9159

NORSK HYDRO ASA

(Exact name of Registrant as specified in its charter)
Kingdom of Norway
(Jurisdiction of incorporation or organization)
Drammensveien 264, Vaekerø
N-0240 OSLO
Norway
(Address of principal executive offices)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
American Depositary Shares	New York Stock Exchange
Ordinary Shares, par value NOK 18.30 per share	New York Stock Exchange*

* Not for trading, but only in connection with the registration of the American Depositary Shares, pursuant to the requirements of the Securities and Exchange Commission.

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: Ordinary Shares, par value NOK 18.30 per share.

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report.

256,712,000 Ordinary Shares, whose par value was then NOK 20.00 per share

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 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 x No o

Indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 o Item 18 x

TABLE OF CONTENTS

In the following discussion, references to Hydro or the Company are to Norsk Hydro ASA or Norsk Hydro ASA and its consolidated subsidiaries, as the context requires. References to the **Group** are to Norsk Hydro ASA and its consolidated subsidiaries. References to the **Kingdom** are to the Kingdom of Norway. The glossary found immediately after the signature page of this annual report provides the definitions of certain other terms used throughout this annual report. In addition, the definitions of oil and gas terms, including terms defined in applicable regulations and Industry Guide 2 (Disclosure of Oil and Gas Operations) of the U.S. Securities and Exchange Commission (the **SEC**), can be found in Item 4.B. of this annual report at the end of the business description for the Exploration and Development sub-segment of Hydro Oil and Energy.

EXCHANGE RATE INFORMATION

The Company publishes its consolidated financial statements in Norwegian kroner (**NOK**). In this annual report, references to US dollar, US dollars, USD US$ or $ are to United States dollars. The following tables set forth, fo periods indicated, certain information concerning the exchange rate of Norwegian kroner for USD 1.00, based on the noon buying rate in the City of New York for cable transfers in foreign currencies as certified for customs purposes by the Federal Reserve Bank of New York (the **Noon Buying Rate**):

Calendar Year Period	Average Noon Buying Rate(1)
1999	7.84
2000	8.83
2001	9.00
2002	7.93
2003	7.06

	Noon Buying Rate	
Calendar Monthly Period	High	Low
December 2003	6.83	6.64
January 2004	7.07	6.66
February 2004	7.07	6.84
March 2004	7.14	6.82
April 2004	7.00	6.82
May 2004	6.97	6.70

(1) The average of the Noon Buying Rates on the last business day of each calendar month during the year indicated.

The Noon Buying Rate on June 18, 2004 was NOK 6.89 = $1.00.

Fluctuations in the exchange rate between the Norwegian kroner and the US dollar will affect the US dollar equivalent of the Norwegian kroner price of the Company s ordinary shares on the Oslo Stock Exchange and, as a result, are likely to affect the market price of the Company s ordinary shares represented by American depositary shares (**ADSs**) in the United States. Such fluctuations could also affect the US dollar amounts received by holders of ADSs on conversion of cash dividends, paid by the Company in Norwegian kroner, on the ordinary shares represented by the ADSs. See Item 3.A. Selected Consolidated Financial Data and Item 10.B. Articles of Association Description of American Depositary Receipts Dividends and Other Distributions.

4

PART I

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

In accordance with the instructions to Form 20-F, the Company does not need to provide the information called for by Item 1 if, as is the case in this instance, the Form 20-F is being filed as an annual report under the Securities Exchange Act of 1934, as amended (the **Exchange Act**).

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

In accordance with the instructions to Form 20-F, the Company does not need to provide the information called for by Item 2 if, as is the case in this instance, the Form 20-F is being filed as an annual report under the Exchange Act.

ITEM 3. KEY INFORMATION

ITEM 3.A. SELECTED CONSOLIDATED FINANCIAL DATA

The following financial information with respect to the five years ended December 31, 2003, 2002, 2001, 2000 and 1999 has been derived from Hydro s audited consolidated financial statements prepared in accordance with United States generally accepted accounting principles (**US GAAP**). The financial information for the three years ended December 31, 2003, 2002 and 2001 should be read in conjunction with and is qualified in its entirety by reference to the consolidated financial statements and notes included in the Company s annual report to shareholders for the year ended December 31, 2003 (the "**Consolidated Financial Statements**), included in Exhibit 10 to this annual report on Form 20-F.

Income Statement Data [1]

	2003	2002	2001	2000	1999
	Year ended December 31, (in NOK million, except per share data)				
Operating revenues [2][3][4]	171,782	167,040	152,999	156,467	111,955
Operating costs and expenses excluding depreciation, impairment and restructuring charges [2][4]	132,431	133,297	118,722	115,328	93,094
Depreciation	15,093	13,912	12,273	12,538	10,494
Restructuring charges [5]		(10)	921	135	632
Operating income before financial and other items	24,258	19,841	21,083	28,466	7,735
Financial and other income (expense), net [6]	1,484	1,670	3,991	5,580	3,193
Interest expense and foreign exchange gain (loss)	(1,266)	517	(3,609)	(3,905)	(3,055)
Income before taxes and minority interest	24,476	22,028	21,465	30,141	7,873
Provision for taxes	(13,937)	(13,278)	(13,750)	(16,178)	(4,337)
Minority interest	148	15	177	18	(90)
Income (loss) before cumulative effect of accounting changes	10,687	8,765	7,892	13,981	3,446
Cumulative effect of accounting change for:					
Start-up costs					(30)
Asset retirement (implementation of SFAS 143)	281				
Net income (loss)	10,968	8,765	7,892	13,981	3,416
Earnings (loss) per share:					
Before cumulative effect of accounting changes	41.50	34.00	30.50	53.40	13.90
	1.10				(0.10)

Cumulative effect of accounting changes					
Earnings (loss) per share:	42.60	34.00	30.50	53.40	13.80
Avg. number of outstanding ordinary shares	257,528,511	257,799,411	258,434,202	261,620,982	247,045,270
Cash dividends paid per share during period:					
NOK per share [7]	10.50	10.00	9.50	8.00	7.50
Converted into USD per share [7]	1.56	1.24	1.05	0.90	0.94

[1] See Note 2 to the Consolidated Financial Statements for a discussion of significant business acquisitions and dispositions during the three-year period ended December 31, 2003.

[2] As of fiscal year 2000, operating revenues for certain trading activities have been presented on a gross basis in the income statement. The amounts for 1999 have been restated to reflect the change. As a result, operating revenues and operating costs have increased by NOK 9,522 million in 1999.

[3] Effective January 1, 2003, Hydro adopted EITF 02-3 Recognition and Reporting of Gains and Losses on Energy Contracts. This standard requires only energy contracts that meet the definition of a derivative according to SFAS 133 Accounting for Derivative Instruments and Hedging Activities and are held for trading be recorded in the balance sheet at fair value. Other energy contracts are recorded at the lower of historical cost and fair market value. This change applies to contracts entered into before October 25, 2002. For contracts entered after October 25, 2002, the regulation applied from initial recognition.

[4] Prior years amounts have been reclassified to reflect the implementation of EITF 02-3 and EITF 03-11, which require realized and unrealized gains and losses on all derivative instruments be presented on a net basis in the income statement. Previously, gains and losses on energy derivative contracts were reported according to EITF 98-10 and were presented on a gross basis in the income statement.

[5] See Note 6 to the Consolidated Financial Statements for more information regarding restructuring charges.

[6] Equity in net income of non-consolidated investees is included under Financial and other income (expense), net.

[7] Cash dividends paid during the period represent payments of dividends with respect to the previous year. Amounts paid in Norwegian kroner have been converted at prevailing exchange rates on the date of such payments.

Balance Sheet Data (1)

	As of December 31, (in NOK million)				
	2003	**2002**	**2001**	**2000**	**1999**
Cash, cash equivalents and other liquid assets	16,830	8,612	29,569	24,257	9,970
Total assets	218,629	207,211	197,922	196,354	177,419
Short-term debt	6,811	9,264	10,424	11,297	8,268
Long-term debt	28,568	30,902	37,853	40,174	42,228
Deferred tax liabilities	34,083	37,071	31,429	31,644	30,573
Ordinary shares and additional paid-in capital	20,403	20,420	20,402	20,391	20,387
Total shareholders equity	80,080	75,867	74,793	71,227	59,497

(1) See Note 2 to the Consolidated Financial Statements for a discussion of significant business acquisitions and dispositions during the three-year period ended December 31, 2003.

Segment Data

The following table indicates the Group s operating revenues, sales to unaffiliated customers and operating income (after eliminating inter-segment sales) by business segment for each of the three fiscal years in the period ended December 31, 2003.

	Operating Revenues			Sales to Unaffiliated Customers			Operating Income/(Loss) Before Financial and Other Income		
Year ended December 31, Business Segment [1]	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Exploration and Production [2]	37,904	32,970	32,426	12,099	10,136	6,992	18,500	13,137	16,910
Energy and Oil Marketing [2]	49,370	45,915	45,824	44,308	41,929	41,315	2,668	2,784	2,267
Eliminations	(27,315)	(23,040)	(26,070)	(1,576)	(965)	(846)	(25)	26	
Hydro Oil and Energy	59,959	55,845	52,180	54,831	51,100	47,461	21,143	15,947	19,177
Metals	39,923	39,646	31,475	26,509	26,025	24,961	2,293	1,690	372
Rolled Products	18,377	14,790	4,228	17,825	14,135	4,126	132	(295)	58
Extrusion and Automotive	24,529	24,245	22,487	24,472	24,186	21,854	98	14	(228)
Other and Eliminations [3]	(13,677)	(13,630)	(7,107)	190	162	1	(67)	289	(17)
Hydro Aluminium	69,152	65,051	51,083	68,996	64,508	50,942	2,456	1,698	185
Hydro Agri	38,174	33,348	37,407	37,828	32,818	36,809	2,800	2,207	2,114
Other Activities [4]	14,013	21,769	22,361	10,206	17,988	17,714	(414)	13	(340)
Corporate and Eliminations [5]	(9,516)	(8,973)	(10,032)	(79)	626	73	(1,727)	(24)	(53)
Total	171,782	167,040	152,999	171,782	167,040	152,999	24,258	19,841	21,083

(1) See Note 2 to the Consolidated Financial Statements for a discussion of significant business acquisitions and dispositions during the three-year period ended December 31, 2003.

(2)

As of January 1, 2003, Hydro s gas transportation activities are reported as part of Energy and Oil Marketing. Prior periods have been reclassified for comparative purposes.

(3) Other and Eliminations includes unrealized gains and losses related to London Metals Exchange (LME) contracts with a loss of NOK 49 million in 2003, a gain of NOK 266 million in 2002 and a loss of NOK 50 million in 2001.

(4) Other Activities consist of the following: Petrochemicals, Treka AS (previously A/S Korn- og Foderstof Kompagniet or KFK), Flexible Packaging, Pronova, the industrial insurance company, Industriforsikring, and Hydro Business Partner.

(5) Corporate and Eliminations includes the elimination of the unrealized gains included in Hydro Energy s results relating to internal sales contracts for power. These eliminations resulted in a charge to Corporate and Eliminations of NOK 141 million in 2003 compared with a gain of NOK 588 million in 2002. Corporate and Eliminations operating income (loss) also includes a net periodic pension cost of NOK 1,146 million for 2003, NOK 312 million for 2002, and a credit of NOK 421 million in 2001.

ITEM 3.B. CAPITALIZATION AND INDEBTEDNESS

In accordance with the instructions to Form 20-F, the Company does not need to provide the information called for by Item 3.B. if, as is the case in this instance, the Form 20-F is being filed as an annual report under the Exchange Act.

ITEM 3.C. REASONS FOR THE OFFER AND USE OF PROCEEDS

In accordance with the instructions to Form 20-F, the Company does not need to provide the information called for by Item 3.C. if, as is the case in this instance, the Form 20-F is being filed as an annual report under the Exchange Act.

ITEM 3.D. RISK FACTORS

In order to utilize the safe harbor provisions of the United States Private Securities Litigation Reform Act of 1995, Hydro is providing the following cautionary statement:

This annual report contains (and oral communications made by or on behalf of Hydro may contain) forecasts, projections, estimates, statements of management s plans, objectives and strategies for Hydro, such as planned expansions, investments or other projects, targeted production volumes, capacities or rates, start-up costs, cost reductions, profit objectives, and various expectations about future developments in Hydro s markets (particularly prices, supply and demand, and competition), results of operations, margins, risk management and so forth. These forward-looking statements are based on a number of assumptions and forecasts, including world economic growth and other economic indicators (including rates of inflation and industrial production), trends in Hydro s key markets, and global oil and gas, and aluminium supply and demand conditions. By their nature, forward-looking statements involve risk and uncertainty and various factors could cause Hydro s actual results to differ materially from those projected in a forward-looking statement or affect the extent to which a particular projection is realized. The following paragraphs address important factors that may cause actual results or developments to differ materially from those expressed or implied by the forward-looking statements.

Risks Relating to Hydro s Oil and Energy Business

Hydro Oil and Energy s future performance depends on the ability to find and develop additional oil and gas reserves that are economically recoverable.

The majority of Hydro Oil and Energy s proved reserves (93 percent as of December 31, 2003) are located on the Norwegian Continental Shelf (the **NCS**). The southern part of the NCS (the location of the most easily accessible and exploitable fields offshore Norway) is a maturing resource province from which reserve additions have been low in recent years. Norway s oil production has been declining for the last two years. See the discussion in Item 4.B. Business Overview Hydro Oil and Energy Exploration and Production Oil Industry Trends Reduced Exploration Results Worldwide and Maturing NCS.

Exploration for oil and gas involves a high degree of risk that hydrocarbons will not be found or that they will not be found in commercial quantities. The 3-D seismic data and other appraisal technologies Hydro Oil and Energy uses do not provide conclusive knowledge prior to drilling a well that oil or gas is present or economically feasible to extract. Accordingly, Hydro Oil and Energy s drilling activity with respect to any particular project area or areas may be unsuccessful. The overall performance of Hydro s exploration activity during the last few years has not met expectations, in particular, the activity on Block 34 in Angola and the drilling activity in the US Gulf of Mexico. See the discussion in Item 4.B. Business Overview Hydro Oil and Energy Exploration and Production Strategy Building the Basis for Future Production.

The cost of drilling, completing and operating a well is often uncertain and can result in cost overruns negatively impacting the potential returns of a given project. Offshore drilling in deep-water (such as in Angola and the US Gulf of Mexico) is extremely expensive and long-term in nature. Drilling operations may be curtailed, delayed or cancelled as a result of factors outside of Hydro s control, such as unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, and shortages or delays in the availability of drilling rigs. Further, completion of a well does not guarantee that it will be profitable or even that it will result in recovery of drilling, completion and operating costs.

Unless Hydro Oil and Energy conducts successful exploration and development activities or acquires properties containing proved reserves, or both, its proved reserves will decline as reserves are produced. In addition, the volume of production from oil and natural gas properties generally declines as reserves from those prospects are depleted. Hydro Oil and Energy s future production is highly dependent upon its success in finding or acquiring, and developing, additional reserves. If unsuccessful, proved reserves will decline, which will, in turn, adversely affect Hydro s results of operations and financial condition.

Hydro Oil and Energy s development projects involve many uncertainties and operating risks that can prevent Hydro from realizing profits and can cause substantial losses.

On the NCS, Hydro Oil and Energy is increasingly developing smaller satellite fields in mature areas. Other Hydro Oil and Energy development projects are in remote locations with limited operational histories and, consequently, the success of these projects is less predictable. In addition, some of Hydro Oil and Energy s development projects are located in deep-water or other hostile environments, such as areas on the NCS, the US Gulf of Mexico and Angola, or produced from challenging reservoirs. Planning and development of the Ormen Lange field, for example, has been described as one of the most challenging assignments any oil company has tackled, not just in Norway but in a global context, given the combination of deep-water, harsh weather conditions, freezing water temperatures and a very uneven seabed. As a result, Hydro Oil and Energy may face increased challenges maintaining targeted levels of production and production growth in future years. This could negatively affect Hydro s results of operations and financial condition.

A substantial or extended decline in oil or natural gas prices would have a material adverse effect on Hydro Oil and Energy s business.

Historically, prices for oil and natural gas have fluctuated widely in response to changes in many factors, including:

- global and regional economic and political developments in resource-producing regions, particularly in the Middle East;

- changes in the supply of and demand for oil and natural gas; and

- the ability of the members of the Organization of the Petroleum Exporting Countries (**OPEC**) to agree on and maintain oil price and production controls.

It is impossible to predict future oil and natural gas price movements. Declines in oil and natural gas prices will reduce Hydro Oil and Energy s results of operations and financial condition, and ability to finance planned capital expenditures. Based on Hydro s analysis of indicative price and currency sensitivities included in this annual report (see Item 5. Operating and Financial Review and Prospects Risk Management), a USD 1 decline in oil prices will reduce Hydro Oil and Energy s pre-tax income and after-tax income by approximately NOK 1,450 million and NOK 390 million, respectively. Lower oil and natural gas prices also may influence the amount of oil and natural gas that Hydro can produce economically or reduce the potential return and viability of projects being considered or in development.

Hydro Oil and Energy is exposed to foreign currency exchange rate fluctuations.

Oil prices are denominated in US dollars while operating results are reported in Norwegian kroner. Accordingly, operating results will, in general, decline when the Norwegian kroner strengthens against the U.S. dollar. Based on Hydro s analysis of indicative price and currency sensitivities included in this annual report (see Item 5. Operating and Financial Review and Prospects Risk Management), a strengthening of the Norwegian kroner against the US dollar of NOK 1 per US$1.00 will reduce Hydro Oil and Energy s pre-tax income and after-tax income by approximately NOK 2,900 million and NOK 785 million, respectively.

Hydro Oil and Energy s oil and gas reserves are only estimates and may prove inaccurate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond the control of the producer. The reserve data included in this annual report represent only Hydro s estimates; the estimates of other companies with interests in the same oil and gas field or fields may differ and the magnitude of the differences may be substantial. This reflects the degree to which reservoir engineering is a subjective and inexact process, requiring the estimate of underground accumulations of oil and natural gas that cannot be measured in an exact manner. Evaluating properties for their recoverable reserves of oil and natural gas entails the assessment of geological, engineering and production data, some or all of which may prove to be unreliable. Accordingly, reserve estimates may be subject to downward or upward adjustment. See the discussion in Item 5. Operating and Financial Review and Prospects Hydro s Critical Accounting Policies Proved Oil and Gas Reserves. Actual production, revenues and expenditures with respect to Hydro Oil and Energy s reserves will likely vary from estimates, and those variances may be material. Any downward adjustment in Hydro Oil and Energy s reserve data could lead to lower future production, which would negatively affect Hydro s results of operations and financial condition.

Hydro may be subject to the imposition of sanctions by the U.S. government in connection with its activities in Iran and/or Libya.

Hydro Oil and Energy is engaged in certain activities in Iran and has an interest in oil and gas exploration licenses in Libya, where exploratory and appraisal wells are in the process of being drilled and limited production has commenced. In August 1996, the United States adopted the Iran and Libya Sanctions Act of 1996 (the **Sanctions Act**) with the objective of denying Iran and Libya the ability to support acts of international terrorism and fund the development and acquisition of weapons of mass destruction. In April 2004, the Bush administration announced the termination of application of the Sanctions Act with respect to Libya, but the Sanctions Act continues in force with respect to Iran.

If the U.S. government were to determine that a person s activities in Iran or Libya are covered by the Sanctions Act, the Act requires the President of the United States to apply two or more sanctions, including a ban on any license to export goods or technology to a sanctioned person, a prohibition of loans or extensions of credit by U.S. financial institutions in an amount greater than U.S.$10 million in any 12-month period to the sanctioned person, and restrictions on imports into the United States from a sanctioned person. The President also has the authority to grant country-specific and project-specific waivers of these sanctions under certain circumstances. To date, there have not been any sanctions imposed against any person or entity under the Sanctions Act, which makes it difficult to predict how any sanctions, if imposed, would be implemented and enforced against an individual company if a violation of the Sanctions Act were to be determined to exist or have occurred.

Hydro cannot predict future interpretations of, or the implementation policy of the U.S. government with respect to, the Sanctions Act. However, taking into consideration the limited size of Hydro s operations in Iran and Libya relative to its total oil and energy activities, as well as Hydro s operations not currently importing from the United

States any goods or technology requiring a license from the U.S. government, the absence, at present, of any loans or extensions of credit from U.S.

financial institutions, and other relevant considerations, Hydro does not believe that imposition of sanctions under the Sanctions Act (should a violation be determined to exist or have occurred) would have a material adverse effect on Hydro s financial condition or results of operations.

Risks Relating to Hydro Aluminium s Business

Hydro Aluminium s results of operations are affected by the cyclicality of the aluminium industry.

The aluminium industry is highly cyclical. Hydro Aluminium s results of operations could be negatively affected as a result of unfavorable economic conditions or conditions affecting the aluminium industry specifically. In particular, Hydro Aluminium is exposed to economic conditions in Europe, as a significant portion of its products is sold into the European market. Virtually all aluminium end-use markets, including the building, transportation and packaging industries, are also cyclical. When downturns occur in these industries, decreased demand for aluminium may result in lower prices for Hydro Aluminium s products, which may have an adverse effect on Hydro Aluminium s results of operations.

Aluminium product prices, reflecting the cyclicality of the aluminium industry, have been volatile historically. Hydro Aluminium expects such volatility to continue. The London Metals Exchange (**LME**) price, in US dollars, is the main reference price for aluminium contracts worldwide. The variance in the LME price can have a material effect upon Hydro Aluminium s results as a whole. The operating results of Hydro Aluminium s Metals sub-segment s upstream operations, in particular, are negatively affected by lower LME prices. Based on Hydro s analysis of indicative price and currency sensitivities included in this annual report (see Item 5. Operating and Financial Review and Prospects Risk Management), a USD 100 decline in the LME price per tonne will reduce Hydro Aluminium s pre-tax income and after-tax income by approximately NOK 875 million and NOK 615 million, respectively.

Hydro makes extensive use of derivatives in managing its aluminium price exposure, which can result in volatility of its accounting results from period to period.

Hydro Aluminium is exposed to foreign exchange rate fluctuations.

The LME price for aluminium is denominated in US dollars. Further, a portion of Hydro Aluminium s production of aluminium is sold in local currencies, including the euro, based on US dollar exchange rates. Accordingly, operating results, which are reported in Norwegian kroner, will be reduced by a strengthening of the Norwegian kroner against the US dollar. Based on our analysis of indicative price and currency sensitivities included in this annual report (see Item 5. Operating and Financial Review and Prospects Risk Management), a strengthening of the Norwegian kroner against the US dollar of NOK 1 per US$1.00 will reduce Hydro Aluminium s pre-tax income and after-tax income by approximately NOK 2,100 million and NOK 1,475 million, respectively.

As a result of Hydro s acquisition in 2002 of the German and overseas smelters of VAW Aluminium AG, a major integrated international aluminium company based in Germany (**VAW**), Hydro Aluminium s Metals sub-segment has reduced Hydro Aluminium s relative exposure to the USD/NOK exchange rate, but increased the exposure to changes in the USD/euro and NOK/euro exchange rates.

Although alumina prices are denominated in US dollars (as are most of Hydro Aluminium s raw materials costs), Hydro Aluminium s Brazilian-based alumina business, through its non-consolidated investee, Alunorte, is exposed to the USD/Brazilian real exchange rate, which can affect Hydro Aluminium s operating results. A decline in the value of the Brazilian real against the US dollar (the US dollar being the predominant financing currency for Alunorte) can lead to a currency loss with respect to the Metals sub-segment s interest in Alunorte. In 2002, currency losses related to Alunorte were NOK 461 million, while changes in currency rates resulted in a currency gain of NOK 218 million for

2003.

Hydro Aluminium s operations are dependent on substantial amounts of energy and, as a result, its profitability may decline if energy costs rise or if energy supplies are interrupted.

Hydro Aluminium s operations consume large volumes of energy, mainly electricity, in producing primary aluminium. Most of Hydro Aluminium s smelters in Norway, Canada and Australia have electricity supply contracts with terms ranging from approximately 7 to 15 years. The electricity supply contracts for Hydro Aluminium s German smelters, scheduled to expire at the end of 2005, will need to be extended or alternative supply arrangements made. Hydro Aluminium may not be able to renew or replace these contracts on comparable terms following the expiry of these contracts. See the discussion in Item 4.B. Business Overview Hydro Aluminium Hydro Aluminium s Operating Sub-Segments Metals Raw Materials Energy.

Reduction in regulation of electricity markets in Europe continues at varying rates of progress from country to country. See the discussion in Item 4.B. Business Overview Hydro Oil and Energy Oil and Energy Government Regulation Liberalization of European Electricity Markets. There is a possibility of new environmental taxes on electricity. Hydro Aluminium is particularly exposed to energy tax regimes in Norway and Germany because of its substantial electricity consumption in these countries. If electricity costs rise as a result of market or other factors such as new taxes, or if electricity supplies or supply arrangements are disrupted, Hydro Aluminium s operating results could decline.

Hydro Aluminium is subject to a broad range of environmental laws and regulations in the jurisdictions in which it operates.

Hydro Aluminium is subject to a broad range of environmental laws and regulations in each of the jurisdictions in which it operates. See Item 4.B. Business Overview Hydro Aluminium Environmental Matters. These laws and regulations, as interpreted by relevant agencies and courts, impose increasingly stringent environmental protection standards regarding, among other things, air emissions, the storage, treatment and discharge of waste waters, the use and handling of hazardous or toxic materials, waste disposal practices, and the remediation of environmental contamination. The costs of complying with these laws and regulations, including participation in assessments and remediation of sites, could be significant. In addition, these laws and regulations create the risk of substantial environmental liabilities, including liabilities associated with divested assets and past activities.

Hydro Aluminium s operating results could decline as a result of government actions or the absence of such actions in respect of third parties, under current or future laws and regulations pertaining to the market and trade in aluminium.

Hydro Aluminium s operating results could decline as a result of government actions such as controls on imports, exports and prices, new forms of taxation, and increased government regulation in the countries in which Hydro Aluminium operates or services customers. In addition, Hydro Aluminium is subject to the disruptive effects of dumped or subsidized products in markets by producers engaging in unfair competition. Such activities may not result in the application of anti-dumping or countervailing duties by appropriate governmental agencies and any such duties imposed may be insufficient to eliminate all of the potential negative effects of such practices. For example, increased quantities of Chinese magnesium available in Western markets contributed to Hydro s decision to close its primary magnesium facility in Norway in 2001, notwithstanding anti-dumping duties imposed on China by the European Community.

In addition, Hydro Aluminium s shipments to certain markets may be subjected to anti-dumping and/or countervailing duties that could negatively affect Hydro s competitive position. Any such actions could affect Hydro Aluminium s revenues, expenses and results of operations.

13

Hydro Aluminium could be adversely affected by disruptions of its operations.

Many of Hydro Aluminium s customers are, to varying degrees, dependent on planned deliveries from Hydro Aluminium s plants located in various parts of the world. Breakdown of equipment or other events leading to production interruptions in Hydro Aluminium s plants could lead to financial losses. Interruption in the energy supply to a smelter for more than six to eight hours could lead to the metal solidifying in the pots (see Item 4.B. Business Overview Hydro Aluminium Overview of the Aluminium Industry Aluminium Smelting), which would result in Hydro Aluminium incurring significant costs to restore the smelter to normal operations. Reduced production, itself, could result in reduced income. Further, customers may have to reschedule their own production due to Hydro Aluminium s missed deliveries, which may result in customers pursuing financial claims against Hydro Aluminium. For example, Hydro Aluminium supplies many of the automotive manufacturers in the world and, in a number of cases, is a sole supplier for special products. The automotive industry is particularly dependent on regular, on-time supplies. The consequences of not meeting scheduled deliveries or quality standards might be costly. Hydro Aluminium s operations may also be unable to meet customers quality demands due to obsolete technology or other problems in Hydro Aluminium s operations. Hydro Aluminium may incur costs to correct any of such problems, in addition to facing claims from customers. Further, Hydro Aluminium s reputation among actual and potential customers may be harmed, potentially resulting in a loss of business. While Hydro Aluminium maintains insurance policies covering, among other things, physical damage, business interruptions, product liability and transportation, these policies may not cover all of Hydro Aluminium s losses.

Risks Relating to the Demerger

Norwegian law subjects Hydro and Yara to joint liability after the Demerger.

As a result of the demerger of Hydro s Agri business (the **Demerger**), which was completed on March 24, 2004, the obligations of Hydro have been divided between Hydro and Yara International ASA (**Yara**), the company formed to act as the transferee company in the Demerger, in accordance with the agreement memorializing the terms of the Demerger (the **Demerger Plan**). For more information on the Demerger, see Item 4.A. History and Development of the Company Demerger of Hydro Agri. If either Hydro or Yara is liable under the Demerger Plan for an obligation that arose prior to completion of the Demerger and fails to satisfy that obligation, the non-defaulting party will, in accordance with applicable provisions of the Norwegian Public Limited Companies Act, be jointly and severally liable for the obligation. This statutory liability is unlimited in time, but is limited in amount to the equivalent of the net value allocated to the non-defaulting party in the Demerger.

In addition to the joint and several liability provided under Norwegian law, Hydro has issued a number of guarantees for the payment and performance obligations of companies that are now part of the Yara group following consummation of the Demerger. The aggregate amounts payable under such guarantees that are limited in amount was approximately NOK 3.4 billion as of March 5, 2004. In addition, Hydro has issued some guarantees that are not limited in amount as credit support for long-term commercial contracts. Although Hydro and Yara are using commercially reasonable efforts to obtain Hydro s release from outstanding guarantees in consideration for the substitution of Yara, there can be no assurance that such releases will actually be obtained.

Certain aspects of the Demerger could cause Hydro to incur tax or tax-related liabilities.

The Demerger involved the separation of the activities of Hydro s Agri business from those of Hydro in a number of countries. Certain of these separations were structured so as not to be subject to tax in Norway and other jurisdictions. However, in certain circumstances, actions taken after the Demerger could cause one or more of the separations, or the Demerger, to be taxable to Hydro. For example, a change in either Hydro s or Yara s business or corporate structure after the Demerger could result in a tax liability for one or more companies within the Hydro

Group because such changes would constitute a breach of the conditions for tax exemption in connection with an earlier transaction.

Risks Relating to Hydro s Shares

Preferential rights may not be available to U.S. holders of Hydro s shares.

Under Norwegian law, prior to Hydro s issuance of any new shares against consideration in cash, Hydro must offer holders of its then-outstanding shares preferential rights to subscribe and pay for a sufficient number of shares to maintain their existing ownership percentages, unless these rights are waived at a general meeting of Hydro s shareholders. These preferential rights are generally transferable during the subscription period for the related offering and may be quoted on the Oslo Stock Exchange (the **OSE**).

U.S. holders of Hydro s shares may not be able to receive, trade or exercise preferential rights for new shares unless a registration statement under the U.S. Securities Act of 1933, as amended (the **Securities Act**) is effective with respect to such rights or an exemption from the registration requirements of the Securities Act is available. If U.S. holders of Hydro s shares are not able to receive, trade or exercise preferential rights granted in respect of their shares in any rights offering by Hydro, then they may not receive the economic benefit of such rights. In addition, their proportional ownership interests in Hydro will be diluted.

Holders of Hydro s shares that are registered in a nominee account may not be able to exercise voting rights as readily as shareholders whose shares are registered in their own names with the VPS.

Beneficial owners of Hydro s shares that are registered in a nominee account (e.g., through brokers, dealers or other third parties) may not be able to vote such shares unless their ownership is re-registered in their names with the Norwegian Central Securities Depository, Verdipapirsentralen (the **VPS**), prior to Hydro general meetings. Hydro cannot guarantee that beneficial owners of its shares will receive the notice for a general meeting in time to instruct their nominees to either effect a re-registration of their shares or otherwise vote their shares in the manner desired by such beneficial owners. See the discussion in Item 10.B Articles of Association Description of Ordinary Shares Voting Rights.

It may be difficult for investors based in the United States to enforce civil liabilities predicated on U.S. securities laws against Hydro, its Norwegian affiliates, or Hydro s directors and executive officers.

Hydro is organized under the laws of the Kingdom of Norway. All of Hydro s directors and executive officers reside outside the United States. Further, a significant portion of Hydro s assets, and those of its directors and executive officers, are located in Norway and other Western European countries. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon Hydro or its directors and executive officers or to enforce against Hydro or its directors and executive officers judgments obtained in U.S. courts predicated on the civil liability provisions of U.S. federal securities laws. Although U.S. investors may bring actions against Hydro, its Norwegian affiliates or any of its directors or executive officers resident in Norway, Norwegian courts are unlikely to apply U.S. law when deciding such cases. Accordingly, there is doubt as to the enforceability, in original actions in Norwegian courts, of liabilities predicated solely on U.S. federal securities laws. Furthermore, judgments of U.S. courts are not enforceable in Norway.

ITEM 4. INFORMATION ON THE COMPANY

ITEM 4.A. HISTORY AND DEVELOPMENT OF THE COMPANY

Historical Overview

Norsk Hydro ASA was organized under Norwegian law as a public company in 1905 to utilize Norway s large hydroelectric energy resources for the industrial production of nitrogen fertilizers. In the years since, energy, in the form of hydroelectric power, natural gas and petroleum, has been the basis for Hydro s growth and the common link among its core business activities.

Since the end of the Second World War, Hydro has expanded into a number of new businesses. In 1951, Hydro began to produce magnesium metal and polyvinyl chloride at Porsgrunn, Norway. In 1967, Hydro opened an aluminium reduction plant and semi-fabricating facilities at Karmøy, Norway, and built the Røldal-Suldal hydroelectric power project to provide energy to the Karmøy facilities.

In 1965 and 1967, Hydro commenced production of ammonia at two large ammonia plants in Norway, one of which made use of naphtha and the other, heavy fuel oil, as feedstocks (i.e., sources of hydrogen) in the ammonia production process. Hydro had previously depended on the electrolysis of water to provide the hydrogen needed to produce ammonia used in nitrogen-based fertilizers. The discovery of natural gas in the Netherlands and on the continental shelf off England in the North Sea created a new and competing source of feedstock for ammonia in Europe. Consequently, Hydro began to take steps to ensure that it could continue to compete with other European producers of ammonia that were obtaining access to these relatively inexpensive natural gas supplies. As a result, Hydro began to investigate various opportunities to participate in oil and gas production. In 1965, Hydro obtained concessions from the Norwegian State to explore for petroleum on the NCS.

Hydro and its partners discovered oil and gas in the Ekofisk field in 1969 and in the Frigg field in 1971. Exploration of these discoveries ensured Hydro a source of feedstock for its fertilizer plants and also brought Hydro into the petroleum refining and marketing business. In 1975, Hydro began oil refining operations at Mongstad, Norway.

Norway s natural gas liquids resources and Hydro s experience in the chemical process industry served as the foundation for its investments in the petrochemicals industry in Norway, and in 1978, Hydro commenced production of ethylene and vinyl chloride monomer.

In the 1980s, Hydro acquired a number of businesses, both in Norway and in other areas. Hydro s expansion of its fertilizer operations resulted in Hydro becoming one of the leading suppliers of fertilizer in Europe. Hydro also entered a new era as an oil company, becoming operator of the Oseberg offshore oil field. Hydro also developed or tested new technologies for deep-water oil and gas production and horizontal drilling, which Hydro subsequently put to commercial use in developing the Troll oil project. In 1986-87, Hydro acquired the Norwegian State-owned aluminium company, Årdal og Sunndal Verk, and several European aluminium extrusion plants from Alcan and Alcoa, thus establishing Hydro Aluminium as a major business within Hydro and an important company in the European aluminium industry.

In 1999, Hydro s management determined to concentrate Hydro s business in three core areas, Oil and Energy, Aluminium, and Agri, and to divest other non-core businesses.

In recent years, each of Hydro s Oil and Energy and Aluminium businesses has grown as a result of substantial investments, including several acquisitions. In 1999, Hydro acquired Saga Petroleum a.s, a Norwegian-based oil company, merging Saga s operations into Hydro Oil and Energy. In 2002, Hydro acquired interests in eight oil and gas licenses on the NCS from the Norwegian State. This acquisition increased Hydro s interests in the Oseberg, Tune and Grane fields, where Hydro is the operator. Hydro paid NOK 3.45 billion (US$415 million) for the license interests which expire between

2015 and 2032. In March 2002, Hydro acquired all the outstanding shares of VAW for a total purchase price, including indirect acquisition costs, of euro 1,911 million (NOK 14.8 billion; US$1.7 billion). Earlier in that same year, Hydro acquired the French building systems supplier, Technal. A significant portion of the expansion of these two core business areas has been financed through the sale of non-core businesses. Since 1999, Hydro has divested non-core businesses with an aggregate enterprise value of approximately NOK 26 billion.

Demerger of Hydro Agri

In the second half of 2001, Hydro s Board of Directors initiated a corporate portfolio strategy project that was concluded in June 2003, when Hydro announced that preparations for establishing Hydro s Agri business as a separate, Norwegian-based company would commence, with the aim of listing the shares of such company on the Oslo Stock Exchange in the first half of 2004. After considering various possible ways of separating Hydro Agri from Hydro, the Board determined that Hydro Agri should be established as a separate, publicly traded company by means of a demerger transaction effected in accordance with Norwegian law. Under Norwegian law, a demerger is the transfer of part of the assets, rights and liabilities of a company (the transferor company) to one or more newly formed or pre-existing companies (the transferee company or companies) in exchange for consideration in the form of shares of the transferee company (or companies) issued to the holders of shares in the transferor company, and possibly other consideration which must not exceed 20% of the total consideration.

On November 10, 2003, Hydro established Yara International ASA, initially named AgriHold ASA, for purposes of acting as the transferee company in the Demerger. Hydro subscribed for all of the initially issued shares of Yara at a total subscription price of approximately NOK 2.0 million. On November 28, 2003, the Board of Directors of the Company and Yara entered into the Demerger Plan. Hydro transferred all assets, rights and liabilities primarily relating to Hydro Agri to Yara on March 24, 2004 (the **Completion Date**), in accordance with the Demerger Plan. The transferred assets consisted primarily of shares, partnership interests and other financial interests held by Hydro in companies (including minority interest companies) and partnerships forming the business activities of Hydro Agri.

In consideration for this transfer of assets, rights and liabilities, Yara issued one of its shares for each Hydro share outstanding on the Completion Date. The Demerger resulted in the split of Hydro s share capital through a reduction of the par value of each Hydro share (from NOK 20.00 to NOK 18.30 per share) simultaneously with the issuance of one new share of Yara for each outstanding Hydro share. The Yara shares issued in the Demerger constituted 80% of Yara s total outstanding shares at the time of completion of the Demerger. These shares were registered in the names of the registered holders of Hydro s shares in the Yara shareholder registry with the VPS on March 30, 2004.

Hydro retained a 20% interest in the Yara shares immediately following the completion of the Demerger. Hydro offered half of these shares in a global offering (the **Global Offering**) that consisted of (i) in Norway, a public offering and an offering to institutional investors; (ii) in the United States, an offering to qualified institutional buyers (**QIBs**) as defined in, and in reliance on, Rule 144A under the Securities Act; (iii) outside Norway and the United States, an offering to institutional investors in reliance on Regulation S under the Securities Act; and (iv) an offering to directors and senior management of Yara. The offer price (the **Offer Price**) was NOK 41 per share. Hydro also granted to the managers of the Global Offering an option (the "**Over-Allotment Option**), exercisable for a period of 30 days starting at the opening of trading of the Yara shares on the Oslo Stock Exchange (which occurred on March 25, 2004), to purchase some or all of the remaining Yara shares held by the Company, at the Offer Price, less underwriting commissions. The managers exercised the Over-Allotment Option in full on March 29, 2004, at which time Hydro ceased to have any equity interest in Yara. The total proceeds from the sale of the Yara shares (including the shares subject to the Over-Allotment Option) amounted to approximately NOK 2.6 billion, resulting in a pre-tax gain of approximately NOK 530 million. The gain has been included in income from discontinued operations in the first quarter of 2004.

With the completion of the Demerger of Hydro Agri, Hydro s core business areas now consist of Oil and Energy, and Aluminium. Hydro is a Fortune 500 energy and aluminium supplier operating in more than 40 countries. Hydro s other activities include: its petrochemicals business; a 68.8 percent interest in Treka AS, whose activities consist of fish feed operations; Hydro Pronova, which is responsible for commercializing products and businesses at the periphery of Hydro s core business areas; Industriforsikring a.s, a captive insurance company; and Hydro Business Partner, which provides service and support functions throughout Hydro.

General Information

As a public limited company organized under Norwegian law, the Company is subject to the provisions of the Norwegian act relating to public limited liability companies (i.e., the Norwegian Public Limited Companies Act). See the disclosure under Item 10.B. Articles of Association Description of Ordinary Shares for a more complete discussion of certain provisions of the Norwegian Public Limited Companies Act.

Following the Demerger, the Company s principal executive offices have been moved to Drammensveien 264, Vækerø, N-0240 Oslo, Norway; telephone number: 47-22-53-81-00. The Company s registered agent in the United States is Trygve Faksvåg, whose address is c/o Norsk Hydro Americas, Inc., 100 North Tampa Street, Suite 3300, Tampa, Florida 33802; telephone number: (813) 222-5700. Hydro s internet site is www.hydro.com.

ITEM 4. B. BUSINESS OVERVIEW

HYDRO OIL AND ENERGY

Hydro Oil and Energy consists of two sub-segments, Exploration and Production and Energy and Oil Marketing.

Exploration and Production consists of Hydro s oil and gas exploration activities, field development activities and the operation of production and transportation facilities.

Energy and Oil Marketing consists of Hydro s commercial operations in the oil, natural gas and power sectors, the operation of Hydro s power stations, management of Hydro s interest in the gas transportation system on the Norwegian Continental Shelf as well as Hydro s seaborne transportation of crude oil, natural gas liquids and other petroleum products and the marketing and sales of refined petroleum products (e.g., gasoline, diesel and heating oil).

Definitions of oil and gas terms used throughout the business description of the Oil and Energy segment are provided at the end of the Exploration and Production business description. These terms have the meanings indicated unless the context indicates otherwise.

EXPLORATION AND PRODUCTION

Introduction and Overview

Exploration and Production s business activities encompass oil and gas exploration, field development and the operation of production and oil transportation facilities. The gas transportation activities were transferred to the Energy and Oil Marketing sub-segment as of January 1, 2003.

Hydro has a strong position on the Norwegian Continental Shelf (NCS), where it is the third-largest producer of equity (i.e., owned) oil and natural gas. In 2003, approximately 89 percent of Hydro s average daily production of 530,000 barrels of oil equivalents (**boe**) was from the NCS. As an operator of 11 producing fields on the NCS with a total production in 2003 of approximately 880,000 boe per day (**boed**), Hydro is a relatively large operator of oil and gas fields, in particular, offshore fields.

Internationally, Hydro s main producing fields are in Angola and Canada. Hydro also has producing fields in Russia and Libya. In addition to these countries, Hydro is involved in exploration activities in other countries, including the United States (Gulf of Mexico) and Iran.

Hydro has a history of delivering strong production growth. From 1998 to 2003, Hydro has nearly doubled its total equity production of oil and gas.

Oil Industry Trends

The main trends in the oil industry affecting Hydro s Exploration and Production activities are described below. Trends affecting the energy market are described under the Energy business description.

High Crude Oil Price Levels

Crude oil prices have been high over the past three years. This has resulted from stronger OPEC market management, political unrest in important producing countries such as Iraq and Venezuela and, of late, increasing world demand combined with a limited margin of unused capacity. Spot Brent Blend crude oil has averaged USD 26.70 per barrel between 2000 and 2003 and has mostly ranged within the USD 22-28 per barrel price band initiated by OPEC for its basket of crude oil types at the beginning of 2000.

OPEC aims to function as a stabilizing force in the market. Its long-term price target is considered to be USD 25 per barrel, which is considered above the marginal cost of new production outside OPEC. As a result, it is reasonable to question whether maintaining this price target is realistic over a longer-term (e.g., 5-20 years) perspective. Should this remain OPEC s price target, crude oil prices could reflect cyclical periods of high and low prices from the interplay between market forces and actions taken by OPEC.

Reduced Exploration Results Worldwide

Based on data from the consulting firm, IHS Energy, worldwide oil and gas exploration activity during 2002-2003 resulted in proportionally smaller discoveries and lower amounts of hydrocarbons discovered compared to previous years.

According to IHS Energy data, a significant trend in 2003 was the dominance of deep-water discoveries. South Atlantic deep-water exploration resulted in 11 of the top 20 discoveries in 2003, seven in Brazil and four in Angola. Other areas with significant discoveries were the Sudan, Vietnam, Indonesia, Mauritania, Egypt and Nigeria. Exploration results offshore Canada, Norway and the UK were disappointing.

Maturing NCS

The NCS, where 93 percent of Hydro s proven reserves are located, is maturing. Norway s oil production has been in decline after 2001, while total production has been increasing due to increased gas production.

In August 2003, Kon-Kraft, a policy group representing the Norwegian petroleum industry, recommended in a report to the Norwegian government certain changes in the petroleum tax regime and other incentives, as well as opening of new areas on the NCS, in order to stimulate more exploration activity, new developments and increasing recovery from existing fields. Hydro believes that there is significant potential for adding new production and value to its NCS portfolio if changes are made in line with the group s recommendations.

As part of the Revised National Budget, passed in June 2004, the Norwegian government made certain changes to the Petroleum Tax Act, which will be put forward in the budget for 2005. These changes are described more in detail under the caption Taxation of Oil and Gas Production. Hydro believes that the changes are moderately positive. For Hydro the changes may stimulate marginal investments in tail-end producing assets, but will have only marginal effects with respect to exploration decisions.

In December 2003, the government announced the extensive 18th Concession Round on the NCS covering 95 blocks or parts of blocks in the North Sea and the Norwegian Sea. At the same time, the government concluded the evaluations of year round petroleum activities in the Barents Sea and the Lofoten area. A decision was made to allow further petroleum activities within areas already open for exploration in the southern part of the Barents Sea with some exceptions. Furthermore, the government decided to discontinue further activities in Nordland VI, an area outside Lofoten. Nordland VI will be reevaluated when the government s integrated management plan for the Barents Sea is completed, which is expected during the winter of 2005/06.

Strategy

Hydro s strategic goal is to position itself as a profitable participant in the upstream oil and gas business based on Hydro s core competencies, including advanced drilling techniques, reservoir management and the development and execution of complex and technologically challenging projects. To achieve its strategic aim, Hydro intends to focus its exploration and production activities on:

- delivering strong production growth through 2007 based on Hydro s existing portfolio in well-defined, profitable projects;
- building the basis for future production growth; and
- improving the profitability of existing assets.

Delivering Strong Production Growth

Hydro has a history of delivering strong production growth. From 1998 to 2003, Hydro nearly doubled its total equity production of oil and gas. The increase included organic growth on the NCS, start-up of production from Hydro s international activities, and the acquisition in 1999 of Saga Petroleum. In addition, during 2002, Hydro acquired increased ownership interests in Hydro-operated fields on the NCS (i.e., Oseberg, Tune and Grane) from the Norwegian State.

Total oil and gas production in 2003 was 530,000 boed, representing an increase of 10 percent over the prior year. This increase reflected the start-up of production from the Grane, Fram Vest and Mikkel fields on the NCS, the second phase of the Kharyaga field in Russia, the Murzuq-A field in Libya and the Jasmim field in Angola. Production also increased from fields (e.g., Tune, Snorre B, Åsgard, Oseberg Sør, Girassol and Terra Nova) that came on stream in recent years. Hydro s increased interests in fields, through the acquisition of such interests from the Norwegian State as described above, also contributed to the growth with a full year effect in 2003.

Hydro has earlier announced a targeted compound annual growth rate for production of 8 percent for the 2001-2007 period. Hydro expects that this production growth will be achieved within its existing portfolio based on producing fields, fields under development and fields planned for development. More than 70 percent of the production in 2007 is expected to come from currently booked proved reserves. Hydro has targeted an average daily production of 560,000 boe for 2004 from fields with currently booked reserves, of which approximately 90 percent is expected to come from currently booked proved reserves. For further information regarding currently booked proved reserves, see the table of proved reserves included in Note 27 to the Consolidated Financial Statements. See, also, the description of fields underlying the growth projections within the disclosure under Item 4.B.

Business Overview Hydro Oil and Energy Exploration and Development Development within this annual report.

In 2003**,** approximately 11 percent of Hydro s total oil and gas production came from outside the NCS, mainly Canada and Angola. Total international oil production was approximately 58,000 boed, an increase of 20 percent compared to the previous year.

Building the Basis for Future Production

Hydro will continue to explore for and develop new oil and gas fields that can contribute to a sustainable production profile for the long-term. The substantial Grane oil field commenced production in September 2003. Development of the Ormen Lange gas field is expected to make a significant contribution to Hydro s income for many years after planned start-up of production in 2007.

Future activity on the NCS will depend on, among other things, whether the tax system and other incentives are adjusted to promote exploration activities, new field developments and increased recovery from existing fields, as well as the access to new prospective exploration areas. The large number of blocks offered in the 18th Concession Round and the announcement by the government of the continuation of year round exploration activity in parts of the Barents Sea are positive developments as seen by Hydro. Hydro believes that there is attractive exploration potential on the NCS, as follows:

Areas around existing infrastructures in the North Sea offer additional oil and gas potential primarily in terms of satellite tie-ins to increase the economic life of current installations. These areas are perceived as moderate risk.

The Norwegian Sea may still have a potential for large gas prospects, although the disappointing results from the exploration on licenses awarded in the 16th Concession Round have increased Hydro s perceived exploration risk in this area.

The northern part of the NCS, including the Barents Sea, a large under-explored area, has potential in terms of both oil and gas prospects, although the perceived risk is high.

Hydro s international expansion has been based on alliances with regional producers and international partners with a focus mainly on oil prospects. Hydro s strategy for international expansion has been to concentrate its efforts in a limited number of areas with sufficient potential to create economic scale. Hydro s technological competence, including the application of leading-edge reservoir and development solutions developed through its experience as an operator of oil and gas producing fields in the harsh Norwegian offshore environment, has provided a solid basis for Hydro s international expansion.

Areas in which Hydro is currently active include the East Coast of Canada, the US Gulf of Mexico, Angola, Russia, Libya and Iran. Activities in Russia, Libya and Iran are in onshore areas that have different cost structures than the activities in the deep-water areas in the US Gulf of Mexico and Angola, providing balance in the portfolio. In general, Hydro strives to balance the total risk in its commercial portfolio by seeking partnerships with other companies to share geological, commercial and political risks.

In light of the maturity of the NCS, Hydro has increased its focus on international exploration opportunities by building up a portfolio of prospects that has been explored mainly over the last three years. In 2001, Hydro s international exploration activity was, for the first time, greater than on the NCS. In 2002 and 2003, international exploration activity represented around three quarters of Hydro s total exploration activity. This, combined with the acreage awarded in the 16th Concession Round on the NCS, has resulted in high exploration budgets, reaching an all time high of around NOK 2.4 billion for 2002.

21

The overall performance of Hydro s exploration activity during the last few years has not met expectations, in particular, the activity on Block 34 in Angola and the drilling activity in the US Gulf of Mexico. As a result, Hydro has completed a thorough review of the past years exploration activities. The results of this review indicate, among other things, that Hydro s portfolio has had too high a share of high risk/high reward prospects. As a result, a more centralized exploration organization has been implemented and exploration activities are being scaled down in 2004 to approximately NOK 1 billion in order to continue the review of the portfolio. In future years, an exploration level of about NOK 1.5 billion is expected.

In addition, Hydro intends to search actively to acquire resources, under the condition that returns will have a clear priority over volume growth, where Hydro can add value based on its core competencies in reservoir management, flow assurance and/or management of development projects. Hydro will primarily concentrate on the geographical areas where Hydro has an active presence, including adjoining areas.

Improving the Profitability of Existing Assets

Hydro continues to pursue cost improvements in its exploration and production activities. As fields on the NCS mature and demonstrate a decline in production, high priority will be given to reducing costs and implementing measures to increase production on existing fields, including development of satellite fields that may be time critical with respect to utilizing existing infrastructure. Hydro s objective is to maintain its status as an efficient operator.

Hydro has announced a targeted production cost in 2004 of NOK 24/boe. The increase of around NOK 3/boe compared to 2003 is, to a large extent, caused by increased gas injection cost on the Grane field in order to increase oil production from that field.

Hydro is actively seeking to concentrate its activities on the NCS by increasing ownership interests in core areas and by selling license interests in non-core areas. The purchase of assets from the Norwegian State in 2002 strengthened Hydro s position in core assets (i.e., the Oseberg, Tune and Grane fields). In recent years Hydro has divested non-core assets on the NCS, including the sale of its equity interest in the Snøhvit field in 2004, which is subject to government approval.

Exploration and Production s Competitive Position

The following discussion includes a description of Hydro s exploration and production positions on the NCS and internationally. This should be read in connection with the description of the relevant risk factors relating to Hydro s Oil and Energy business included in Item 3.D.

Strong Position on the NCS

Hydro is the third-largest producer on the NCS, trailing Petoro (the Norwegian State oil and gas holding company) and the majority-State controlled Statoil. In 2003, approximately 89 percent of Hydro s average daily equity production of 530,000 boe came from the NCS.

As of December 31, 2003, Hydro had interests in 102 licenses on the NCS, of which it was operator of 48 licenses. In total, the licenses cover a gross offshore area of around 33,000 square kilometers (km) in the North Sea, the Norwegian Sea and the Barents Sea. Hydro also has interests in four exploration areas with a total of 12 optional licenses on the NCS, of which it is operator of one area. Each of the optional licenses may turn into a license under normal conditions if the partners commit to an exploration well following seismic evaluations. These four exploration areas cover an additional gross area of more than 18,000 square km.

Hydro is the operator of 11 producing oil and gas fields on the NCS: Oseberg, Oseberg Øst (East), Oseberg Sør (South), Brage, Tune, Njord, Troll Oil (Troll B and C), Heimdal, Vale, Grane and Fram Vest. Hydro is also the operator of the development phase of the large Ormen Lange gas field, for which the Plan for Development and Operation (**PDO**) was approved by the authorities in April 2004.

The total average daily production in 2003 from Hydro-operated fields was approximately 880,000 boe. This means that Hydro is a relatively large operator of oil and gas fields, in particular offshore fields. Measured in terms of equity production, however, Hydro is a medium-sized upstream oil and gas company. This is partly due to the Norwegian licensing system, under which a relatively low equity interest historically has been awarded to an operator.

Hydro has an equity interest in most of the main producing oil and gas fields on the NCS. The most important producing fields for Hydro in 2003 were the fields in the Oseberg area, the Troll field and fields in the Tampen area. Other important fields were the Åsgard field, the Sleipner fields and the Ekofisk fields. In the coming years, the Grane oil field, which started production in 2003, will be an important contributor to Hydro s Norwegian oil production. The Ormen Lange field is the largest field presently under development on the Norwegian Continental Shelf and Hydro expects that Ormen Lange will be an important part of Hydro s production after start-up in 2007.

Hydro has a strong focus on optimizing its portfolio on the NCS through reducing its interest in or selling non-core assets and increasing its ownership share in its core areas. In January 2004, Hydro signed an agreement with Statoil for the sale of Hydro s equity share in the Snøhvit field. At the same time, Hydro agreed to purchase an additional equity interest in the Kristin field from Statoil, which will improve Hydro s position in the Norwegian Sea. The Norwegian authorities approved the transaction during the second quarter of 2004 subject to certain commercial conditions which are expected to be resolved during the third quarter of 2004. In 2003, Hydro also entered into an agreement to sell its interest in the Gjøa field, which is presently in the pre-development phase. That sale was completed in the first quarter of 2004.

Interesting International Positions

In 2003, Hydro s international oil production increased by 20 percent compared to the previous year and represented approximately 11 percent of its total oil and gas production. The main producing fields are in Angola and Canada. Hydro also has producing fields in Russia and Libya. In addition to these countries, Hydro is involved in exploration activity in other countries, including the United States (Gulf of Mexico) and Iran.

Angola: Hydro has participated in Angola s oil and gas industry since 1991. Hydro s main asset is its 10 percent interest in the deep water offshore Block 17, where a total of 15 discoveries have been made as of December 31, 2003. This includes Girassol and Jasmim, which contributed an average of almost 20,000 boed of oil production in 2003, as well as the Dalia field that is under development. Further geological and engineering studies are planned in order to appraise newly discovered structures, including the Acacia and Hortensia discoveries that were announced in the spring of 2003.

Hydro also holds a 30 percent interest and is the technical assistant to the Angolan national oil company, Sonangol, the field operator, on Block 34. The first well, drilled in April 2002, did not result in the discovery of hydrocarbons. A second exploratory well, drilled in December 2003, discovered gas, but was considered a non-commercial well. Technical evaluations are continuing to identify potential targets for a third well in the block. As of December 31, 2003 , Hydro s two exploration licenses in Angola in total cover a gross exploration area of around 9,000 square km, mainly deep-water or ultra deep-water acreage with water depths down to 2,600 meters.

Canada: In 1996, Hydro entered into a strategic alliance with Petro-Canada that entailed a swap of certain Hydro interests in licenses on the NCS in exchange for the right to participate in oil production from proven fields and explore for further oil discoveries on the Grand Banks. Hydro presently has ownership in two producing fields, Hibernia and Terra Nova. These fields contributed a total average oil production of approximately 30,000 boed in 2003. Hydro is also working together with

the operator, ChevronTexaco, to develop the Hebron field in the same area. Hydro is also evaluating the Annapolis discovery located offshore of Nova Scotia to determine possible development solutions. As of December 31, 2003, Hydro s 16 exploration licenses in Canada in total cover a gross exploration area of approximately 25,000 square km, including shelf and deep-water acreage with water depths ranging from 50 to 3,100 meters.

Russia: Hydro has been present in Russia for 15 years and has equity production from the onshore Kharyaga field in the Timan Pechora basin. This field started production in 1999 and phase two came on stream in 2003. Further development of the field is being planned. In 2003, average equity production was 5,500 boed. Hydro is also pursuing new business opportunities in Russia. In 2003, Hydro signed a technical cooperation agreement with Rosneft for the evaluation of development scenarios relating to the giant Shtokman gas field, located in the deep water continental shelf on the Russian side of the Barents Sea. In June 2004, the Russian gas company, Gazprom, indicated that Hydro could become one of the most important partners in the Shtokman field. A work group shall now draw up a proposal for the concrete agreements for Hydro s possible participation in the development of the field. There are a number of issues to be clarified, including the progress plan for the development, ownership stakes and other conditions.

Libya: Hydro is a partner in the onshore Mabruk field, which lies in the northern part of the country. In addition, Hydro has taken part in oil exploration in the Murzuq Basin, in the Sahara Desert, since 1998. Production in the Murzuq Basin started in the autumn of 2003 from the A-field and in June 2004 from the D-field. Total average daily equity production from Hydro s Libyan fields was around 2,000 boed in 2003. Libya represents an interesting resource potential. Hydro anticipates continuing to pursue new opportunities in Libya in light of the currently improving general political situation there. As of December 31, 2003, Hydro s four licenses in Libya cover a gross onshore area of around 37,000 square km.

Iran: Hydro established an office in Tehran, Iran during November 1999. In April 2000, Hydro entered into a contract with the National Iranian Oil Company for the exploration of the Anaran Block close to the Iraqi border. The Anaran Block covers an area of approximately 3,200 square kilometers, of which Hydro will acquire 1,000 km of 2D seismic and drill 5 wells. The contract has a term of 4.5 years with an option for a one-year extension. Hydro has applied for extension of the contract. The agreement provides Hydro with the right to enter into negotiations for a buy-back agreement to develop reserves in the event of a commercial discovery. After clearing minefields, Hydro completed the seismic acquisition program. The first well was spudded in the spring of 2003, but drilling proved to be more difficult than anticipated, and the well was abandoned in January 2004. New wells will be drilled during 2004. Hydro s farm-out of 25 percent of the interest in the Anaran contract to the Russian company, Lukoil, was approved by the Iranian authorities in 2003, leaving Hydro with an equity share of 75 percent. Hydro s prime objective in Iran is to focus on completion of the exploration program on the Anaran Block. A successful completion of the activity in Anaran may better position Hydro for new opportunities in Iran.

US Gulf of Mexico: Hydro entered into a joint venture agreement with ConocoPhillips in September 2001. This agreement provided Hydro with a 25 percent working interest in five firm and three contingent exploratory wells in the US Gulf of Mexico. An obligation to participate in the fifth firm well was later eliminated and the joint venture agreement amended to provide for Hydro s participation in the ConocoPhillips-operated Lorien prospect. The Lorien prospect was drilled in 2003 and resulted in a discovery believed to be commercial and is planned to be developed as a tie-back to existing infrastructure. During the first quarter of 2004, Hydro purchased an additional ownership interest in the Lorien discovery in the US Gulf of Mexico, increasing its ownership from 10 to 30 percent. The other four firm wells did not result in commercial discoveries. Evaluation of prospects relating to leases in ConocoPhillips portfolio that Hydro has options to participate in will continue in 2004. In total, Hydro s 63 exploration leases as of December 31, 2003 in the US Gulf of Mexico, of which Hydro is an operator of 14 leases, cover an exploration area of around 1,500 square km, mainly deep-water acreage with water depths down to 2,300 meters. Hydro has concentrated its efforts in the US Gulf of Mexico in the Walker Ridge and Green Canyon areas to establish a good geological knowledge base in the area. In the most recent lease sale in April 2004, Hydro was awarded seven new exploration blocks, all in these areas.

In addition, Hydro has two exploration licenses in **Denmark.** Hydro had one exploratory license in **Trinidad and Tobago**, which was relinquished in February 2004.

Exploration

The following tables reflect the number of exploratory oil and gas wells drilled by Hydro as of December 31, 2003. The first table reflects all the gross exploratory wells drilled and completed during the years indicated. The second table reflects the exploratory wells in the process of being drilled as of December 31, 2003. A total of 13 wells were drilled and completed in 2003, of which three were considered productive. In addition, two wells were in the process of being drilled at year-end, of which one resulted in a commercial discovery and one was abandoned.

Drilling Activity

		Norway			International			Total		
		2003	**2002**	**2001**	**2003**	**2002**	**2001**	**2003**	**2002**	**2001**
Exploratory wells	Productive[1]	2	6	8	1	8[3]	7	3	14[3]	15
(presented on a gross basis)	Dry[2]	4	5	10	6	12	4	10	17	14

(1) A productive well is an exploratory well deemed to be commercially viable.

(2) A dry well is an exploratory well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(3) Includes the Acacia and Hortensia discoveries in Angola. These wells were drilled during 2002 and the result announced in 2003.

In Process Drilling Activities

As of December 31, 2003		**Norway**	**International**	**Total**
Exploratory	Gross[1]	0	2	2
	Net[2]	0	1	1

(1) A gross well is a well in which a whole or fractional working interest is owned.
(2) A net well is the sum of the whole fractional working interests in gross wells which equal one.

In 2004, Hydro plans to participate in approximately 20 exploratory wells. Around half of these are planned on the NCS and the remaining are planned internationally, mainly in Iran, Angola and Libya.

Norway

In 2003, Hydro participated in six exploratory wells on the NCS, and was operator for two of the wells. Two of the exploratory wells resulted in commercial discoveries (the Klegg and Ringhorne Øst (East) discoveries in the North Sea). Hydro is the operator of Klegg and intends to submit a Plan for Development and Operation of the discovery before December 2004. Production is expected to start-up in 2006. Hydro is considering developing this small discovery through a sub-sea development connected to the Heimdal field or other installations in the area. Hydro holds an equity interest of 28.5 percent in Klegg. The Ringhorne Øst discovery is the second oil discovery on Ringhorne and is being evaluated for connecting to the existing infrastructure on Ringhorne, Balder and/or Jotun. Hydro has an ownership interest of 45 percent in production license 169 that covers part of the discovery.

In March 2003, Hydro was awarded operatorship in two licenses and partnership in one license in the North Sea area through the 2002 annual North Sea round. In December 2003, Hydro was awarded operatorship in six licenses and partnership in three licenses under the new system of Awards in Predefined Areas that includes mature areas close to existing or planned infrastructure.

The Norwegian authorities announced the 18th Concession Round in December 2003 covering 95 blocks or parts of blocks in the Norwegian Sea and the North Sea. At the same time, the government decided to allow further year round petroleum activity in the Barents Sea South, excluding certain valuable areas. However, the government decided not to continue further petroleum activities in the Nordland VI area outside Lofoten. This decision will be reevaluated when the government s integrated management plan for the Barents Sea is completed. In June 2004 Hydro was granted operatorship in two licenses and partnership in two licenses in the awards of the 18th Concession Round.

In January 2004, the Norwegian authorities announced a new round of Awards in Predefined Areas covering mature areas close to existing or planned infrastructure in the North Sea, the Norwegian Sea and the Barents Sea. The deadline for application is October 1, 2004. Awards are expected to take place in December 2004.

International

In 2003, Hydro s international exploration activities encompassed Angola, Canada, Libya, Iran, and the United States (Gulf of Mexico). Hydro participated in seven exploratory and appraisal wells that were completed during 2003. One discovery was made in the Gulf of Mexico. In addition, two wells were in the process of being drilled at year-end.

In **Angola**, one well was drilled on Block 25 during 2003. This well did not result in a commercial discovery and the block was relinquished to Sonangol at the end of the exploration period on December 31, 2003. In December 2003, the second exploratory well on Block 34 was drilled. While gas was discovered, the well was not considered to be commercially viable. Technical evaluations are continuing to identify potential targets for a third well in the block. In April 2003, the Acacia and Hortensia discoveries on Block 17 were announced, based on exploratory drilling in 2002.

In **Canada**, none of the three wells drilled during 2003 resulted in commercial discoveries. New exploration wells are planned for 2004.

In **Libya**, one exploratory well was ongoing at year-end, which resulted in a commercial discovery. The exploration and appraisal program in Libya will continue in 2004 with the planned drilling of further wells. In the first quarter of 2004, a delineation well on Block 186 was completed, resulting in additional commercial resources.

In **Iran**, the Anaran well was spudded in spring 2003 and was abandoned in January 2004 due to technical difficulties. New wells are planned for 2004.

In the **US Gulf of Mexico**, Hydro participated in two wells during 2003, one of which resulted in the Lorien discovery, believed to be commercially viable.

In **Denmark**, Hydro has a 25 percent interest in license 6/98 with the Hejre discovery. An appraisal well is planned for 2004. In addition, the second commitment well on license 4/98 is presently under evaluation.

Reserve Information

At the end of 2003, Hydro s share of proved developed reserves of oil and gas was estimated to be 1,558 million boe. Hydro s share of proved undeveloped reserves accounted for an additional 730 million boe. Total developed and undeveloped proved reserves amounted to 2,288 million boe, of which gas reserves represented approximately 57 percent.

Reserve life, defined as the number of years of production from proved reserves at the present production level, was approximately 12 years at the end of 2003, with approximately 7 years for oil and approximately 27 years for gas.

The following table summarizes Hydro s net quantities of proved oil and gas reserves as of December 31, 2003, 2002 and 2001.

Oil and Gas Reserves

Oil in millions of boe Gas in billions of cubic feet (bcf)	2003 Norway	2003 Int [1]	2003 Total	2002 Norway	2002 Int [1]	2002 Total	2001 Norway	2001 Int [1]	2001 Total
Proved oil reserves, developed and undeveloped [2]	839	154	993	883	172	1055	825	193	1,018
Of which developed	690	88	778	559	93	652	564	62	626
Proved gas reserves, developed and undeveloped[2]	7,317		7,317	6,629		6,629	5,986		5,986
Of which developed	4,415		4,415	4,416		4,416	3,669		3,669
Proved oil and gas reserves, developed and undeveloped (in millions of boe)[2]	2,134	154	2,288	2,053	172	2,225	1,880	193	2,073
Of which developed	1,470	88	1,558	1,339	93	1,432	1,211	62	1,273

(1) Reserves reflected in the International columns are shown net of royalties and the government s share of profit oil.

(2) For the definition of proved reserves, proved developed reserves and proved undeveloped reserves, and applicable conversion factors, see Definitions of Oil and Gas Terms at the end of the Exploration and Production business description.

Hydro s reserve replacement ratio in 2003, including purchase and sale of reserves, was approximately 133 percent. Excluding purchase and sale of reserves, the ratio was approximately 134 percent.

Proved reserves are estimates and are expected to be revised as oil and gas are produced and additional data become available. Accordingly, recoverable reserves are subject to upward and downward adjustments from time to time. Please see the discussion in Item 5. Operating and Financial Review and Prospects Hydro s Critical Accounting Policies Proved Oil and Gas Reserves.

An analysis of changes to proved developed and proved undeveloped reserves of oil and gas as of and for the three years ended December 31, 2003, 2002 and 2001 is included in the table in Note 27 to the Consolidated Financial Statements. Estimates of the proved reserves, presented on an individual field basis, as of December 31, 2003, can be found in Exhibit 99.2 to this annual report.

Development

In 2003, Hydro invested NOK 8,487 million in the development of new and existing fields and transportation systems compared to NOK 8,222 million and NOK 7,763 million in 2002 and 2001, respectively. The implementation of SFAS 143 relating to asset retirement obligations resulted in an additional charge of NOK 1,089 million for 2003, which is not included in the above amount. For more information on Hydro s adoption of SFAS 143, see Note 1 to the Consolidated Financial Statements. Hydro s three most important development projects in 2003 were the Grane, Kristin and Snøhvit fields.

A summary of the fields under development as of December 31, 2003, is included in the following table. Only the main fields are presented in the table. Development projects in connection with fields under production and smaller satellite developments relating to fields in production are described under the caption Production below.

Development

Fields under Development[1]

Field	Type of Field	Approved for Development	Production Scheduled to Commence	Total Estimated Investment[2] (in NOK billion)	Investment Incurred to Date [2] (in NOK billion)	Hydro s Equity Share
Norway						
Ormen Lange[3]	Gas/Condensate	April 2004	October 2007	51.6	0	18.0728%
Kvitebjørn	Gas/Condensate	July 2000	October 2004	9.8	7.5	15%
Kristin	Oil/Gas	December 2001	October 2005	17.5	8.2	12%[4]
Byggve/Skirne[5]	Gas/Condensate	July 2002	March 2004	2.0	1.5	10%
International						
Dalia	Oil	April 2003	October 2006	24.4	2.6	10%
Murzuq D[6]	Oil	August 2003	June 2004	2.1	0.5	8%

(1) The table does not include the Snøhvit field because an agreement was entered into with Statoil in January 2004 for the sale of Hydro s equity interest in the field.

(2) Total Estimated Investment and Investment Incurred to Date amounts are as of December 31, 2003. These amounts represent the total estimated investment based on the Plan for Development and Operation or current cost estimate and total incurred investment for the applicable field, respectively. All amounts are in nominal values.

(3) The Ormen Lange PDO was submitted to Norwegian authorities on December 4, 2003. The PDO was approved by the authorities in April 2004. The total estimated investment for Ormen Lange excludes the cost of the Langeled gas export pipeline.

(4) Hydro s interest in the Kristin field will increase to 14 percent if the Norwegian authorities approve the agreement entered into with Statoil in January 2004, under which Hydro has agreed to purchase an additional equity interest in the field. The operator of the Kristin field, Statoil, has announced an expected increase in the estimated investment level.

(5) The Byggve/Skirne field started production in the beginning of March 2004.

(6) The total estimated investment relates to the Murzuq A and D fields, which are an integrated development. Production from the A-field started in October 2003 and from the D-field in June 2004. Hydro has an equity interest of 20% in the exploration phase, 10% in the development phase and 8% in the production phase.

In connection with the development projects described in this section, Hydro has invested NOK 0.4 billion, NOK 0.9 billion and NOK 2.3 billion for the years 2001, 2002 and 2003, respectively. Estimated investments for the same projects for 2004, 2005 and 2006 are NOK 4.6 billion, NOK 6.4 billion and NOK 4.4 billion, respectively.

Norway

The PDO for the **Ormen Lange** gas field was submitted to the Ministry of Petroleum and Energy on December 4, 2003, together with the Plan for Installation and Operation (**PIO**) for the new gas export pipeline, Langeled. The authorities approved both the PDO and the PIO in the beginning of April 2004. Ormen Lange is situated in water depths of 850 to 1,100 meters in the Norwegian Sea, 100 km off the northwest coast of Norway. Based on seismic and other data, Ormen Lange is believed to be the second-largest gas field and the largest field presently under development in Norway. Given Hydro s estimate of the total proved reserves for the field, Hydro s share is 234 million boe including 35.0 billion cubic meters (bcm) of gas. The field development is planned as a sub-sea installation linked to the Nyhamna onshore processing plant not far from the city of Molde in Norway. Gas is to be exported from the plant through a new pipeline (Langeled) via the Sleipner riser platform to Easington on the east coast of England. Langeled will be merged with the Gassled pipeline joint venture after start-up of operations of the southern leg of the pipeline in 2006. Production is scheduled to begin in October 2007. The total investment, in nominal terms (i.e., not discounted to present value), is estimated at NOK 71.8 billion, including NOK 51.6 billion for field and plant development and NOK 20.2 billion for the pipeline. Hydro s equity share is 18.0728 percent. Hydro is the operator during the development phase of the field.

The **Kvitebjørn** gas and condensate field is situated southeast of the Gullfaks field. The field is to be developed using a fixed production platform. Rich gas will be transported through a new pipeline to the Kollsnes gas terminal for processing and export. Condensate will be transported through the new Kvitebjørn oil pipeline to the Mongstad terminal. Production is scheduled to commence in October 2004. Given Hydro s estimate of the total proved reserves for this field, Hydro s share is 49 million boe, including 5.4 bcm of gas. Hydro s equity share is 15 percent.

The **Kristin** oil and gas field is situated in the Norwegian Sea, approximately 20 km south of the Åsgard field. The field will be developed with sub-sea production facilities tied back to a semi-submersible production platform. Gas will be exported through the Åsgard transport pipeline while condensate will be loaded offshore from Åsgard C. Production from the field is expected to commence in October 2005. Given Hydro s estimate of the total proved reserves for this field, Hydro s share, based on its current 12 percent equity interest, is 36 million boe, including 2.3 bcm of gas. As previously announced, Hydro has adjusted downward the reserve estimates of certain fields as of December 31, 2003, from that reflected in its 2003 annual report to shareholders following the conclusion of a dialogue initiated with the staff of the SEC relating to the reserve estimate for Ormen Lange. Kristin was one of those fields. The downward adjustment for Kristin was 3 million boe or eight percent. In January 2004 Hydro entered into an agreement with Statoil to increase its interest in the Kristin field to 14 percent. The Norwegian authorities approved the transaction during the second quarter of 2004 subject to certain commercial conditions which are expected to be resolved during the third quarter of 2004.

In January 2004, Hydro announced that it had entered into an agreement to sell its equity share in licenses relating to the **Snøhvit** field to Statoil. The Norwegian authorities approved the transaction during the second quarter of 2004 subject to certain commercial conditions which are expected to be resolved during the third quarter of 2004. The authorities approved the development concept for the Snøhvit field in March 2002. The plan consists of a sub-sea development with a pipeline to the LNG plant at Melkøya, close to Hammerfest, for processing. Statoil, the operator, announced in June 2004 that the total Snøhvit investments may increase by NOK 4-6 billion to between 49.3 and 51.3 billion, of which NOK 10.1 billion was invested as of December 31, 2003. Hydro s equity share in the field prior to entering into the agreement was 10 percent, representing proved reserves of 71 million boe, including 9.5 bcm of gas, based on Hydro s estimate of the total proved reserves. Hydro has adjusted downward the reserve estimate for Snøhvit as of December 31, 2003, by 19 million boe (21 percent) from that reported in its 2003 annual report to shareholders.

The **Skirne** and **Byggve** gas and condensate fields are situated approximately 20 km east of the Heimdal field. The fields will be developed with a wellhead platform at each field tied to the Heimdal gas center. Production started in March 2004. A booster compressor module will be installed on the Heimdal field in 2005. Given Hydro s estimate of the total proved reserves for the fields, Hydro s share is 4 million boe, including 0.5 bcm of gas. Hydro s equity share is 10 percent.

International

Angola: The Dalia field is the third development on Block 17 and was sanctioned by the Angolan government at the end of April 2003. The development concept comprises a sub-sea production system linked to a floating production and storage-offloading unit with an average production capacity of 225,000 boed. Production is expected to commence in October 2006. Given Hydro s estimate of the total proved reserves for this field, Hydro s share is 35 million boe. In light of the delay in the expected timing of final approval of the development of the Rosa/Lirio field, Hydro has determined to remove from its portfolio of proved reserves its estimate of 26 million boe of proved reserves that were booked for this field.

Libya: The field development plan for the onshore Murzuq D-field was submitted for approval to the Libyan authorities in October 2002 and was approved in August 2003. Production started in June 2004. The field development is integrated with the A-field 30 km away, which started production in October 2003. Oil from the field will be transported to the El Sahara field 29 km away, where it will be blended with oil from El Sahara and transported by a 800 km pipeline to the As Zawiyah terminal west of Tripoli. Given Hydro s estimate of the total proved reserves for the Murzuq fields, Hydro s share is 10 million boe. Hydro s equity share is 20 percent in the exploration phase, 10 percent in the development phase and 8 percent in the production phase.

Production

The following table includes the number of gross and net productive oil and gas wells in which Hydro had interests as of December 31, 2003.

Type of well		Norway (1)	International	Total
Crude oil	Gross	546	101	647
	Net	72	18	89
Natural gas	Gross	88	0	88
	Net	11	0	11

(1) Includes 43 wells with multiple completions (i.e., more than one formation producing into the same well bore). If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

The following table reflects Hydro s share of the average daily production of oil and gas from fields in which Hydro had an interest during 2003 and 2002. Information regarding the total production of oil and gas in 2003, Hydro s ownership interest, the remaining production period of the producing fields and the license period for such fields can be found in the table included in Exhibit 99.2 to this annual report.

Hydro s Share of Average Daily Production[1]

Field	2003 Total (in thousands of boe)	2003 Oil[2] (in thousands of boe)	2003 Gas (in millions of cubic feet)	2002 Total (in thousands of boe)	2002 Oil[2] (in thousands of boe)	2002 Gas (in millions of cubic feet)
Oseberg fields[3]	115.1	103.0	59.6	114.5	97.7	89.3
Troll	80.0	37.0	248.1	79.7	37.7	242.5
Snorre fields[4]	67.5	65.0	12.8	66.4	63.6	14.6
Åsgard	40.6	24.2	91.6	33.5	21.5	67.4
Sleipner fields[5]	35.2	12.0	127.0	34.1	11.8	122.3
Tune	30.8	7.8	122.0	0.4	0.1	1.6
Ekofisk fields[6]	28.2	23.9	23.0	28.6	24.0	24.9
Gullfaks fields[7]	26.0	21.2	26.8	24.9	21.0	22.3
Norne	13.2	12.2	5.9	15.6	14.6	5.9
Brage	7.3	7.0	1.9	9.9	9.4	2.3
Visund	6.6	6.6		8.2	8.2	
Njord	6.1	6.1		7.2	7.2	
Grane	5.5	5.5				
Frigg	3.9		22.6	4.0		23.1
Fram Vest	2.9	2.9				
Mikkel	1.5	0.7	4.4			
Vale	1.3	0.7	3.2	0.5	0.2	1.2
Heimdal	0.8	0.2	3.7	1.2	0.3	5.3
Varg				3.5	3.5	
Total Norway	**472.5**	**336.0**	**752.6**	**432.2**	**320.8**	**622.7**
Terra Nova	20.1	20.1		15.8	15.8	
Girassol	19.5	19.5		17.6	17.6	
Hibernia	10.1	10.1		9.0	9.0	
Kharyaga	5.5	5.5		3.4	3.4	
Mabruk	2.1	2.1		2.4	2.4	
Jasmim	0.2	0.2				
Murzuq	0.2	0.2				
Total Int l	**57.7**	**57.7**		**48.2**	**48.2**	
Total	**530.2**	**393.7**	**752.6**	**480.4**	**369.0**	**622.7**

(1) For information regarding conversion factors for the measurement units in the table, please see Definitions of Oil and Gas Terms at the end of the Exploration and Production business description.

(2) Includes crude oil and NGL/condensate.

(3) Includes Oseberg, Oseberg Vest, Oseberg Sør and Oseberg Øst fields.

(4) Includes Snorre, Tordis, Tordis Sørøst, Tordis Øst, Borg, Vigdis, Statfjord Øst and Sygna fields.

(5) Includes Sleipner Vest, Sleipner Øst, Gungne and Sigyn fields.

(6) Includes Ekofisk, Eldfisk, Embla and Tor fields.

(7) Includes Gullfaks, Gullfaks Vest, Gullfaks Sør, Gullveig and Rimfaks fields.

Norway

Oseberg Fields. The Oseberg fields are core areas for Hydro on the NCS, contributing 24 percent of Hydro s total NCS production in 2003. The Oseberg Fields include the main Oseberg field (the Field Center installations and the Oseberg C production platform) and the two satellite fields, Oseberg Øst (East) and Oseberg Sør (South). Oil and gas from the satellites are piped to the Oseberg Field Center for processing and transportation. Oil is brought ashore through the Oseberg Transport System pipeline to the Sture terminal in Norway. Gas is exported through the Oseberg Gas Transport pipeline to the Heimdal field and further through the Gassled pipeline system. Oil production from the Oseberg Field Center and the Oseberg C platform are currently in the decline phase. Natural gas export from the Oseberg Field Center and Oseberg Øst and Oseberg Sør began in 2000 and 2001, respectively. In February 2003, a revised PDO for the development of the Oseberg Sør field was sent to the authorities for approval, and was approved in May 2003. The revised PDO covers the J-structure that will be developed with a separate sub-sea installation with production start-up in October 2004. The total cost for the J-development is estimated at NOK 1.6 billion, of which NOK 0.2 billion was invested as of December 31, 2003. The Plan for Development and Operation of the Oseberg Vestflanken (West flank) was submitted to the authorities in October 2003 and approved in December 2003. Production start-up is planned for October 2005. Oseberg Vestflanken is planned to be developed by a sub-sea installation tied into the Oseberg Field Center platforms. Total investments are estimated at NOK 2.3 billion, of which NOK 23 million was invested as of December 31, 2003. Hydro s equity share in the Oseberg fields is 34 percent.

Troll Field. The Troll field is the largest gas field on the NCS. Gas from the Troll field represents a major part of Hydro s current developed gas reserves and gas production. In 2003, approximately one-third of Hydro s gas production came from the field. The gas development consists of a platform linked to the Kollsnes gas terminal. The gas is exported from Kollsnes through the Gassled system. Gas production started in 1996. Troll is also a major oil field. The oil development on the western part of Troll is operated by Hydro and consists of two floating production units linked by two oil pipelines to the Mongstad terminal. Oil production started in 1995.

Snorre Fields. The Snorre fields are located in the Tampen area and include the Snorre, Tordis, Vigdis, Statfjord Øst and Sygna fields. Production of oil and associated gas from the **Snorre field** began in 1992. The Snorre B platform came on stream in June 2001. Oil and gas from the Snorre field is piped to the Statfjord field for processing, storage and transportation. Production of oil and gas from the **Tordis field** began in 1994. Oil from the Tordis field is processed on the Gullfaks C platform. Production from the field peaked in 1996 and is currently in the decline phase. Since the Tordis field started declining, several satellite structures have been connected to the field including Tordis Øst in 1998, Borg in 1999 and Tordis Sørøst in 2001. In 1999, water injection was implemented to increase the recoverable reserves from the field. Production of oil and gas from the **Vigdis field** began in early 1997. Production began declining in 2000. To maintain production levels, a PDO for the Vigdis Extension was submitted to and approved by the government in 2002 with production start-up in October 2003. Oil from the Vigdis field is processed on the Snorre platform and piped to Gullfaks A for storage and transportation. The **Statfjord Øst** and **Sygna** fields started production in 1994 and 2000, respectively. Both fields are linked to the Statfjord C platform.

Åsgard Field. The Åsgard field is situated in the Norwegian Sea. The Åsgard Unit covers the three fields, Midgard, Smørbukk and Smørbukk Sør. The field is developed with a production ship (Åsgard A) for oil and condensate production and a floating production platform (Åsgard B) for condensate and gas production and a storage vessel (Åsgard C). Oil production started in May 1999 and gas export commenced in October 2000. The gas is transported through the Åsgard Transport pipeline to the Kårstø gas terminal for processing. Since the commencement of production, average gas export from Åsgard B has varied due to considerable technical problems. However, the platform is now in stable production at maximum available gas capacity.

Sleipner Fields. Production of gas and condensate began at **Sleipner Øst** in late 1993 and from **Sleipner Vest** in the middle of 1996. Production from the satellite fields, **Gungne**, **Loke Trias** and **Sigyn**, began in 1996, 1999 and 2002, respectively. Gas from Sleipner is exported through Gassled and the condensate is transported to the Kårstø facilities. In 2002, a decision was made to develop the northern part of the Sleipner Vest field with three sub-sea wells. These wells are expected to come on stream during the second half of 2004.

Tune Field. The Tune gas and condensate field (phase 1) developed as a sub-sea satellite to Oseberg, came on stream in November 2002, using spare processing capacity at the Oseberg Field Center and was a major contributor to Hydro s growth in production in 2003. A decision to develop Tune phase 2 was made in June 2004, with start up of a single well planned for October 2005.

Ekofisk Fields. Ekofisk is situated in the southern part of the North Sea and is the oldest operating field complex within Hydro s portfolio, having commenced production in 1971. Oil is exported through the Norpipe oil pipeline to Teesside in England, while gas is exported through the Gassled system. In 1984, subsidence of the seabed around the complex was observed as a result of gradually decreasing reservoir pressure. In 1987, water injection started with the result that subsidence now is under control and reservoir pressure has returned to its original level. At the same time installations were raised to a higher level. In 1998, the new Ekofisk II facilities replaced old production facilities. Problems related to the gas processing equipment have affected and continue to affect production efficiency relating to gas output; however, measures have been introduced to limit the effects on oil production. Gas production rates are expected to increase after planned repair during a maintenance shutdown scheduled for August 2004. Abandonment of the satellite platforms is ongoing and alternatives are being discussed for extending the lifetime of the centrally located Ekofisk I and Eldfisk platforms in order to increase both well potential and production capacities. The Ekofisk Area Growth project includes installing a new wellhead platform tied in to the Ekofisk II process platform. The authorities approved the Plan for Development and Operation in June 2003, with potential first production in the third quarter of 2005. Total investments for the Ekofisk Area Growth project are estimated at NOK 8.5 billion, of which NOK 1.0 billion was invested as of December 31, 2003. Hydro s equity share is 6.65 percent. Alternatives for further development of the Eldfisk and Tor field are being discussed among the owners.

Gullfaks Fields. The Gullfaks fields are situated in the Tampen area. The main Gullfaks field consists of three integrated platforms, where production started in 1986. The satellite fields, **Gullfaks Vest**, **Gullveig**, **Rimfaks** and **Gullfaks Sør**, are linked to the main field. Oil is transported by tankers from the fields while gas is transported by pipeline to the Kårstø terminal in Norway. A decision to develop the Gulltopp satellite was concluded by the license owners at the end of 2003. Production is planned to start in July 2005. Gulltopp will be developed by a long extended reach well from the Gullfaks A platform. The total project investment is estimated at approximately NOK 0.3 billion. Hydro s equity share is 9 percent. Due to the nature and small size of the investment, the authorities will not require the submission of a PDO for the development.

Norne Field. The Norne field is located in the Norwegian Sea. Oil production started in late 1997. Gas production started in February 2001. The installation consists of a combined production and storage vessel with gas handling facilities and a gas transportation pipeline. The gas is transported via the Åsgard transportation pipeline to the Kårstø gas terminal in Norway. In May 2004, the PDO for Norne satellites was submitted to the Norwegian authorities. A decision by the authorities is expected during the summer of 2004. The two discoveries are due to be developed with sub-sea installations tied back to the existing installation. Total investments are estimated to be NOK 3.6 billion. Hydro s equity share is 13.5 percent.

Brage Field. The Brage field is located in the North Sea, approximately 13 km east of the Oseberg Field Center. Production began in 1993. Oil from the field is transported to the Sture terminal via the Oseberg Field Center. Production from the field is currently in the decline phase. As part of Hydro s active management of its oil and gas portfolio, Hydro entered into an agreement in 2002 with OER Oil AS to reduce its ownership in Brage to 20 percent. The authorities approved the transaction in 2003.

Visund Field. The Visund field is situated in the Tampen area. The field is developed with a floating production unit that came on stream in early 1999. Oil produced from Visund is stored in and shipped from Gullfaks A. A sub-sea installation for developing the northern reservoir of Visund was put

33

on stream in early 2002. In October 2002, the authorities approved the plan for development and operation of the Visund Gas Extension, which covers development of the gas volumes. The project includes increased gas treatment and injection capacity and a gas export pipeline connected to the Kvitebjørn gas pipeline for transport to the Kollsnes terminal. Gas export is expected to start in October 2005. The total investment is estimated at NOK 2.2 billion, of which approximately NOK 0.4 billion was invested as of December 31, 2003. Hydro s equity share is 20.3 percent.

Njord Field. The Njord field is located in the Norwegian Sea. Production from the field began in late 1997. The installation consists of a floating production unit (Njord A) combined with a tanker, Njord Bravo, for storage and loading of oil. Gas produced is re-injected into the field to maintain reservoir pressure. As part of Hydro s active management of its oil and gas portfolio, Hydro entered into an agreement in 2002 with OER Oil AS to reduce its ownership in Njord to 20 percent. The transaction was approved by the authorities in 2003.

Grane Field: The Grane field is located in the North Sea and is developed with an integrated production and drilling platform. Production from the field started three weeks ahead of schedule on September 23, 2003. Oil from the field is exported in a new pipeline from the Grane platform to the Sture terminal in Øygarden, Norway. Gas for injection into the field will be imported through a 50 km pipeline from the Heimdal Gas Center to ensure optimum production of oil. The Grane field contains heavier oil than is normally found on the NCS and is therefore expected to be sold at a lower price than, for example, Brent Blend.

Frigg Field. It is currently anticipated that the Frigg gas field will be permanently shut down in 2004.

Fram Vest Field. The field is located approximately 22 km from the Troll field. The field is developed by a sub-sea installation linked to the Troll C platform for processing. Production commenced in October 2003. Processed oil is transported to the Mongstad terminal while gas will be used for re-injection for a period of approximately six years to facilitate oil recovery. After this period, gas will be transported to the Kollsnes gas terminal. Hydro is currently evaluating further sub-sea developments in the Fram region, phased in to the existing Troll installations as soon as there is available capacity.

Mikkel Field. The Mikkel field is located in the Norwegian Sea and started production in October 2003. The development concept consists of sub-sea installations linked to the Åsgard B platform for processing. The condensate will be exported from Åsgard C for offshore loading. The gas will be transported to the Kårstø terminal through the Åsgard transport system.

Vale Field. The Vale field was developed by one satellite well that is tied to the Heimdal Gas Center. Production started in May 2002. In July 2004, the production will be suspended due to drilling of a new sidetrack well. Production is expected to start up again in October 2004.

Heimdal Field. The Heimdal gas and condensate field is currently operated as a gas processing and distribution center after reconstruction of the platform in 2000 and 2001. Production of remaining reserves began in August 2001 after a temporary shut down during the construction period. This tail end production is expected to last until June 2005. In March 2004, production started from the small Skirne and Byggve fields, which are connected to the Heimdal Gas Center.

International

Angolan Fields. The **Girassol** field is an offshore field located on Block 17 in Angola. Oil production started in December 2001. The installation consists of a production and storage-offloading vessel that is the largest of its type ever built. The processing capacity is above 200,000 boed and the storage capacity is two million barrels. Hydro has a working interest of 10 percent. The **Jasmim** field is a sub-sea satellite connected to the Girassol field. Production started in November 2003.

Canadian Fields. Both of Hydro s producing fields in Canada are located in the Grand Banks area off the east coast of Newfoundland. Oil production from the **Hibernia** field came on stream in November 1997. Hydro has a five percent interest in the field. The **Terra Nova** field is southeast of Hibernia and started production in January 2002. Hydro has a working interest of 15 percent.

Russian Fields. The **Kharyaga** field is located in Northwest Russia. Production commenced in October 1999 under the Production Sharing Agreement (PSA) entered into with the Russian authorities. Hydro s share in the PSA is 40 percent. Production from phase 2 of the project has been gradually phased in since May 2003. A third phase is planned to further increase the total production from 2007.

Libyan Fields. Production from the **Mabruk West** field in the north of Libya started in 1995. Hydro became owner of a 25 percent interest in the license through the acquisition of Saga in 1999. Production from the **Murzuq A**-field in the south of Libya started in October 2003 and from the Murzuq D-field in June 2004. The Murzuq A- and D-fields are being developed as an integrated unit. Hydro s equity share is eight percent of the production phase.

Transportation of Oil and Gas

Norway

Effective January 1, 2003, ownership of the major gas transportation pipelines on the NCS was merged into a new joint venture named Gassled. This is described in more detail in the business description for Energy and Oil Marketing below, which includes more comprehensive information regarding Hydro s ownership share in Gassled than is reflected in the table below.

The information in the following table reflects Hydro s interest in the major pipelines for the transportation of oil and gas from the NCS and in the corresponding land terminals as of December 31, 2003.

Pipeline	End Point	Length (km)	Hydro s percentage interest
Gassled (gas)	From the NCS to Germany, Belgium, France and the U.K.	>6,000	11.134[1]
Langeled North[2]	Nyhamna Sleipner (Norway)	630	17.96
Langeled South[2]	Sleipner Easington (U.K)	540	17.14
Norpipe Oil A/S (oil)	Ekofisk - Teesside (U.K.)	354	3.50
Oseberg Transport System (OTS) (oil)	Oseberg - Sture (Norway)	115	22.23
Frostpipe (oil)	Frigg - Oseberg (Norway)	82	13.75
Sleipner Øst NGL pipeline (NGL)	Sleipner - Kårstø (Norway)	245	10.00
Troll Oil 1 & 2 (oil)	Troll - Mongstad (Norway)	165	9.73
Grane Oil Pipeline (oil)	Grane Sture (Norway)	212	24.40
Grane Gas Pipeline (gas)	Grane Heimdal (Norway)	50	38.00
Norne Transport (gas)	Norne- Åsgard (Norway)	130	8.10
Vestprosess (NGL)	Kollsnes/Sture Mongstad (Norway)	56	17.00

[1] Initial interest.

(2) The plan for installation and operation was approved by the authorities in April 2004. The final route is to be decided.

The **Sture** terminal outside Bergen receives crude oil and condensate from the Oseberg fields, Brage, Veslefrikk and Huldra through the Oseberg Transport System (OTS), and since 2003, from the Grane field through the Grane Oil Pipeline. The terminal started operations in 1988. The Sture terminal includes facilities for further processing of crude oil and for production of LPG (a mix of propane and butane gases). The Sture terminal has the same ownership structure as OTS excluding the LPG facilities that are owned 100 percent by Hydro and the export facilities for NGL that are owned by Vestprosess DA, in which Hydro has an equity share of 17 percent.

International

Crude oil from the Hibernia and Terra Nova fields in Canada is transported from the fields in dedicated offshore loading tankers directly to market or to a terminal located at Whiffen Head, Newfoundland. Hydro has an ownership interest in two of the tankers of 14.9 percent and 12.7 percent, respectively, and a 5 percent interest in the terminal. In addition, Hydro has long-term contracts for use of storage capacity at the terminal. The terminal has been expanded to accommodate the commencement of production at Terra Nova.

Definitions of Oil and Gas Terms

Term	Definition
bbl	Barrels
bcm	Billion cubic meters (Sm3)
boe	Barrels of oil equivalents
boed	Barrels of oil equivalents per day
bcf	Billion cubic feet
cf	Cubic feet measured at 60 degrees Fahrenheit. See also Sm3
condensate	Light hydrocarbon substances produced with natural gas, which condense into liquid at normal temperatures and pressures associated with surface production equipment.
development well	A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. See Regulation S-X, Rule 4-10(a)(11).
dry well	An exploratory well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
exploratory well	A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. See Regulation S-X, Rule 4-10(a)(10).
field	An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. See Regulation S-X, Rule 4-10(a)(8).
gross well	A well in which a whole or fractional working interest is owned.
LNG	Liquefied natural gas. A liquid composed chiefly of natural gas (i.e., mostly methane). Natural gas is liquefied to make it easy to transport if a pipeline is not feasible (as across a body of water). Not as easily liquefied as LPG, LNG must be put under low temperature and high pressure or under extremely low (cryogenic) temperature and close to atmospheric pressure to become liquefied.
LPG	Liquefied petroleum gas, a liquid composed chiefly of butane and propane.
net well	The sum of the whole or fractional working interests in gross wells that equals one.
NGLs	Oil and gas condensate and natural gas liquids. For purposes of converting quantities of NGL cited in this annual report, 1 ton NGL = 11.951 boe.

PDO	Plan for development and operation
proved reserves, , proved developed reserves, proved	Proved reserves are estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate

Term	Definition
undeveloped reserves	with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. For a more complete understanding of these terms, see Regulation S-X, Rule 4-10(a)(2), (3) and (4). This information can be accessed on the website of the SEC at www.sec.gov.
PSA	Production sharing agreement.
reservoir	A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. See Regulation S-X, Rule 4-10(a)(9).
Sm3	Standard cubic meters measured at 15 degrees C. For purposes of converting quantities of natural gas cited in this annual report, 1 Sm^3 = 35.3826 cubic feet. When converting natural gas into barrels of oil equivalents, Hydro makes an adjustment for calorific value to an equivalent 40 MegaJoule/Sm^3 volume. 1000 Sm^3 of natural gas = 6.2898 boe.

ENERGY AND OIL MARKETING

While Energy and Oil Marketing represents a single sub-segment within the Oil and Energy business segment, Hydro believes that the business activities of Energy and Oil Marketing are better explained through a separate discussion of their respective activities.

ENERGY

Overview

Energy s business activities include:

- marketing of Hydro s equity oil production, including gas liquids;
- marketing of Hydro s equity gas production as well as third-party sourced gas to customers, primarily on the European continent;
- managing Hydro s interest in the gas transportation system on the NCS and Hydro s sea-borne transportation of crude oil, NGLs and other petroleum products;
- production and sale of electricity generated at hydroelectric power plants in Norway;
- sourcing Hydro s natural gas and power requirements for its Norwegian and European industrial facilities; and
- developing Hydro s hydrogen and renewable energy business activities.

Hydro has an established position in the European natural gas and power markets as a producer of natural gas and power, a holder of an equity interest in the natural gas transportation systems, an active trader in the markets, and through customer portfolios in the industrial/wholesale markets for both natural gas and electricity. By combining all commercial activities for energy products and services in one operating segment, Hydro leverages its commercial skills and contacts in each of the energy sectors. Hydro s experience as a major producer and consumer of energy products has enabled it to provide services to major electricity customers in the Nordic region. Its experience in the Nordic region contributes to Hydro s knowledge base in pursuing opportunities in other markets.

As part of its development of the business activities, Hydro in 2003 acquired Duke Energy s Dutch gas marketing operations (Duke Energy Europe Northwest B.V.) and entered into an agreement with the German gas transportation and supply company, Wingas GmbH, to set up a joint venture for marketing and sales of natural gas in the UK. Furthermore, Hydro sold its interest in the Scanraff refinery and no longer holds an ownership interest in the refining business.

Industry Trends

Liberalization of European Energy Markets

In Europe, both the gas and electricity markets are undergoing liberalization as a result of European Union (**EU**) policy. For more information on the EU s regulatory initiatives to further the liberalization of EU energy markets, see Oil and Energy Government Regulation Liberalization of European Electricity Markets below.

Growth in European Natural Gas Demand

The demand for natural gas in Europe is, by some estimates, expected to grow significantly from the 2002 level of approximately 500 bcm, fueled in large part by demand from the electric power industry. However, the timing of the electricity sector s increase in gas consumption is uncertain. Current market conditions in continental Europe appear not to justify new investment in gas for power facilities at the present time. However, the Nordic region is experiencing a trend of much tighter electricity supply, as experienced during the winter of 2002/03, and gas for power production may become economic sooner in this area than in continental Europe.

In 2002, Norway supplied approximately 13 percent of the total consumption of natural gas in Europe. This percentage is expected to rise in future years based on existing contract commitments and remaining reserves. The United Kingdom, in particular, is an attractive market for Norwegian gas due to the maturing of U.K. North Sea fields, which is expected to result in a decline of production by 2005. Given its close proximity, the NCS is considered a competitive source for new deliveries. Norwegian fields are presently linked to the United Kingdom through the Vesterled pipeline to St. Fergus, which can handle 11-12 bcm of natural gas per year. In 2003 the Norwegian and U.K. authorities agreed on the main principles for a treaty relating to new pipelines between the two countries, making possible the shipment of gas from new gas fields, such as the Ormen Lange field, to the United Kingdom.

Integration of Energy Markets

Along with the liberalization of the energy markets in Europe, there is a trend towards integration of the electricity and gas markets because the business models are, to a large degree, based on the same competence and types of customers.

Increased Focus on Renewable Energy and Hydrogen

There is an increasing interest in renewable energy and the utilization of hydrogen in the energy market in developed economies throughout the world. The major political drive and basis for a number of public support schemes is driven by concerns about the security of energy supply and environmental considerations. The European Union has adopted a directive (Directive 2001/77/EC) that seeks to promote the production of electricity from renewable energy sources, including wind and hydropower. EU Member States are encouraged by the directive to set targets in line with global expectations of 12 percent of gross domestic energy consumption by 2010. A more efficient renewable energy framework is expected to be developed in Norway and implemented in 2005/06. This is expected to increase focus on wind energy in an area characterized by having relatively good wind conditions.

Strategy

Hydro s strategy is to further enhance its position in the Northern European energy market, based on increasing gas production and commercial competence gained from the European gas market and the liberalized Nordic power market. Focus areas comprise:

- enhancing the value of Hydro s crude oil portfolio;
- enhancing the value of Hydro s natural gas portfolio;
- optimizing Hydro s power activities; and
- pursuing hydrogen and renewable energy opportunities.

Enhancing the Value of Hydro s Crude Oil Portfolio

The focus of Hydro s marketing efforts with respect to its North Sea and international crude oil production is to achieve optimal prices by marketing fewer grades of crude oil, in larger volumes, while minimizing logistical costs. Swap arrangements result in savings in logistical costs, particularly with respect to production from Hydro s international crude oil portfolio.

Trading activities include the sale of Hydro s crude oil, refined oil products and NGL production. The volumes of these activities have increased partly due to increased equity oil and gas production over the past years. Furthermore, Energy supplies NGL feedstock to Hydro s petrochemical plants, as well as the former Hydro Agri (now Yara) fertilizer plants. Following the Demerger, Hydro expects to continue to supply the Yara fertilizer plants under arm s-length agreements.

In 2003, Hydro sold its 25 percent interest in the Scanraff oil refinery, located at Lysekil, Sweden, to the oil company, Preem, which owned the other 75 percent of the refinery at the time of the transaction. As a result, Hydro no longer holds an ownership interest in the refining business. Hydro is now sourcing the refined products requirements for its Swedish retail marketing activities through a long-term supply agreement with Preem.

The tables below reflect the volumes of Hydro s sales and refining activities, respectively, in the last three years.

Sales (thousands of tonnes)	**2003**	**2002**	**2001**
Crude oil/NGL	18,560	19,068	17,507
Oil products	2,808	2,326	2,912

Refining (thousands of tonnes)	**2003[1]**	**2002**	**2001**
Gasoline	797	660	841
Diesel fuels, gasoils, etc.	766	796	897
Heavy fuel oil	502	550	440
Other	77	36	66
Total refining	2,142	2,042	2,244

(1) Volumes for 2003 are through December 17, 2003, the effective sales date of Scanraff.

Enhancing the Value of Hydro s Natural Gas Portfolio

Because of location, transportation infrastructure and substantial reserves, Norwegian natural gas is competitive in the European region. Hydro is the third-largest producer on the NCS. Hydro has an interest in all the major natural gas fields and in Gassled, the gas pipeline joint venture on the NCS. Hydro also holds capacity rights in Gassled, enabling access to five landing points for natural gas in Europe. This offers a flexible and favorable position with respect to capturing value in the market. In the European continental market, Hydro has achieved an attractive position through a combination of long-term sales contracts, long-term supply contracts and access to transportation.

Hydro s strategy is to combine its role as a natural gas producer with that of a wholesaler and trader to increase its market share in the developing liberalized European natural gas market. The main geographic focus is Northwest Europe. The wholesale market includes larger industrial customers, power companies and local distribution companies, as well as the traditional transmission companies. Hydro wants to develop a strong and balanced customer portfolio, including a mix of long-term contracts with wholesalers, end-user sales to the power and industrial segments, and spot sales, in order to optimize its natural gas portfolio.

A major focus for Hydro in 2003 was increasing the value of Hydro s natural gas portfolio through, among other things, more optimal utilization of Hydro s production and transportation capacity. These upstream positions, combined with Hydro s market presence across Europe, provide Hydro with an opportunity to create business further down the gas value chain in Northwest Europe. Further growth will be based on both increased access to natural gas from fields in which Hydro has an equity interest and sourcing natural gas in the market. In line with this strategy, Hydro in 2003 acquired Duke Energy s gas sales and marketing organization in the Netherlands (Duke Energy Europe Northwest B.V.), which has a portfolio of sourcing, sales, transportation and storage agreements.

Furthermore, Hydro entered into a sourcing contract with Maersk, the Danish oil company, which will deliver 0.6 bcm/year of gas from the Danish Continental Shelf into the Netherlands for five year starting in 2005. In December 2003, Hydro also entered into an agreement with the German gas transportation and supply company, Wingas GmbH, to set up a joint venture, HydroWingas, for marketing and sales of natural gas in the UK. The main goal in pursuing this joint venture is to establish a competitive and effective U.K. gas marketing channel by combining Wingas and Hydro s gas positions and marketing skills. HydroWingas commenced marketing activities in the spring of 2004.

The table below reflects Hydro s equity gas production and downstream non-equity gas sales and sourcing in the last three years.

(in bcm)	**2003**	**2002**	**2001**
Equity natural gas production	7.8	6.4	5.4
Sales of non-equity gas	3.8	3.7	2.4

In 2003, Hydro s equity natural gas production from the NCS amounted to 7.8 bcm, an increase of 22 percent compared to the previous year.

In addition to its equity gas, during 2003 Hydro supplied 3.8 bcm in the downstream market based on non-equity natural gas, including 2.0 bcm supplied to Hydro s industrial factories (mainly those of the former Hydro Agri) on the European continent. Following the Demerger, Hydro expects that deliveries will continue to be governed under arm s-length agreements.

Natural gas produced from fields in which Hydro has an equity interest is mainly sold under long-term contracts. Pricing under long-term contracts is generally based on a price formula whereby the natural gas price is indexed to oil product prices in the end-user market, mainly gas oil and low sulphur fuel oil. These contracts typically have provisions for price reviews based on changes in certain market conditions.

In the future, Hydro expects an increasing volume of its natural gas will be sold under short-term contracts. Physical positions are still necessary in order to gain increased margins by optimizing logistics and trading. However, more natural gas is available on the European continental short-term market and liquidity is increasing at new hubs, complementing the existing long-term, bilateral agreements between producers and large end-users and distributors. Hydro intends to evolve its trading activities as liquidity increases. Such market developments have been evident in the United Kingdom for some time and similar developments are underway on the European continent, most notably around the market hubs in Zeebrugge in Belgium and in the Netherlands.

Hydro has made substantial investments in natural gas export capacity from the Oseberg and Troll fields, together comprising a major portion of its proved reserves of natural gas. This capacity will enable Hydro to increase exports of gas significantly in the coming years as reservoir conditions allow higher natural gas production. The start-up of the Ormen Lange gas field will further increase Hydro s gas production and the development of the connected Langeled transportation system will further increase transportation flexibility on the NCS.

Gassled, the new natural gas transportation infrastructure joint venture on the NCS, has been in operation since January 1, 2003. The NCS natural gas pipelines and associated terminals had previously been organized as several different joint ventures owned by oil companies and the Norwegian State. Gassled consists of the following systems: Europipe, Europipe II, Norpipe gas pipeline, Zeepipe, Franpipe, Vesterled, Statpipe, Oseberg Gas Transport, Åsgard Transport and the Kårstø terminal. The Kollsnes gas terminal is included in Gassled from February 1, 2004. Currently

Hydro holds a direct ownership interest of 11.134 percent in Gassled. Hydro s participation in future capacity expansions such as Langeled will initially result in a moderate increase in Hydro s ownership interest before it is expected to be reduced to about 10 percent in 2011 in accordance with the agreed redistribution of ownership shares.

Optimizing Hydro s Power Activities

Hydro is one of the largest producers of power in Norway, with a normal annual production from hydroelectric facilities in Telemark, Røldal/Suldal and Sogn of approximately 8.3 terrawatt hours (**TWh**). Hydro is presently engaged in a large development project to expand the Tyin hydropower plant in Sogn at a cost of approximately NOK 1.5 billion. In 2003, Hydro disposed of its interest in Sundsfjord Kraft ANS in exchange for a 20.2 percent ownership interest in the power producing company, SKS Produksjon AS. Hydro has title concessions that do not revert to the Norwegian government for power plants with an average generating capacity of 2.7 TWh per year. This represents approximately 33 percent of Hydro s normal production capacity. The remaining production capacity, 5.6 TWh, or approximately 67 percent of Hydro s normal production capacity, will revert to the Norwegian government without compensation at the expiration date of the concessions. Separate concessions apply to each power plant. The year of expiration of the individual concessions ranges from 2022 to 2051 and does not include a phase-out period. In addition to its hydroelectric power stations, Hydro is a partial owner of the Havøygavlen wind power plant with an expected total annual production of 120 gigawatt hours (GWh).

Since the liberalization of the Norwegian electricity market in 1991, Hydro has developed trading and marketing activities, along with analysis, portfolio and risk management systems. Hydro s Nordic electricity portfolio includes owned generation facilities, long-term supply contracts, internal and external sales contracts and short-term optimization contracts.

The table below reflects Hydro s power production and the volumes acquired under long-term purchase contracts for the last three years.

(in TWh)	2003	2002	2001
Power production	7.5	10.3	9.8
Acquired under long-term contracts for Hydro s industrial use	7	7	7

As reflected in the table, production in 2003 was lower than normal due to low precipitation in Norway during the autumn and winter of 2002/03.

Energy supplies electric power to Hydro s industrial plants in Norway. To meet those needs, Hydro has entered into long-term purchase contracts, the majority of which are with the Norwegian State-owned power company, Statkraft. These long-term contracts provide assurance of the availability of and predictable prices for a certain quantity of power to Hydro s power intensive industries. In 1997, Hydro entered into an agreement with Statkraft to purchase electricity from 2000 to 2020. The agreement replaces supplies under existing contracts, which terminate during the 2006-2010 period.

More recently, Hydro has started to build a European continental electricity portfolio based on optimizing supply to Hydro s larger consuming plants, including plants that are now owned by Yara. Hydro is providing Nordic and European continental customers with structured energy products and energy services ranging from physical power supply to advanced hydro-power optimization, pricing services and portfolio management, including market analysis, price forecasting and risk management/trading.

Hydro intends to continue to expand into new markets and grow its Nordic and European continental power portfolios based on demonstrated profitability while controlling risk.

Pursuit of Hydrogen and Renewable Energy Opportunities

Hydro has extensive experience within the traditional industrial hydrogen markets as well as with renewable hydroelectric energy production. Hydro is seeking to leverage its experience to position itself in renewable energy and new energy markets for hydrogen.

Hydro views wind power generation as the most important part of the renewable energy market and is making selective investments in this market. In 2002, Hydro completed the Havøygavlen wind park, located in northern Norway, in which Hydro holds a 44 percent interest. Havøygavlen is one of the largest wind power projects in Norway, with an expected annual output of around 120 GWh. Further Norwegian and European projects are continuously evaluated, in Norway pending the framework for production and sale of renewable energy.

Hydro is presently involved in several hydrogen projects. These include filling stations for hydrogen-fueled vehicles in Iceland and Germany, and combining hydrogen and wind power to form a demonstration project of a sustainable energy society on the Norwegian island of Utsira.

OIL MARKETING

Oil Marketing markets and sells refined petroleum products (gasoline, diesel and heating oil) and electricity to customers in Scandinavia and the Baltic countries. Hydro owns 100 percent of its oil marketing unit in Sweden and 50 percent of Hydro Texaco, an oil marketing company with retail outlets in Norway, Denmark and the Baltic countries. Hydro markets a range of complementary energy products in addition to refined petroleum products, such as electricity, natural gas, biogas for cars and bioenergy for heating purposes, as well as convenience store goods.

At the end of 2003, Hydro s retail network in Sweden comprised 526 gasoline stations and 124 Hydro Diesel service stations. Hydro operates both Hydro and the Uno-X branded stations in the Swedish gasoline market. Approximately 50 percent of the station network is Hydro-branded. As of year-end 2003, Hydro Texaco operated 407 gasoline outlets and 46 diesel sites in Norway, 443 gasoline outlets and 106 diesel sites in Denmark, and 43 gasoline outlets and 10 diesel sites in the Baltic countries with Hydro Texaco or Uno-X brands. Hydro s strategy is to maximize its return on investments already made in its gasoline station chains by focusing on the most profitable stations and closing smaller and unprofitable outlets, building strong brand recognition and expanding on profitable segments of the market.

Hydro has a strong brand and market position in the most profitable segments of the industrial and residential heating oil markets. Its large customer base offers a platform for the sale of electricity to residential and industrial customers. Also, Hydro s and Hydro Texaco s large customer bases provide a potential for cross-sales. Sales of electricity have, to date, been relatively modest compared to Hydro s sale of gasoline and gasoil, but are growing.

Gasoline is sold through service stations and unmanned, automated stations in all of Hydro s markets. Gasoils are sold through automated diesel stations and through direct deliveries from depots to end consumers.

Volumes (thousands of m^3) (1)	**2003**	**2002**	**2001**
Gasoline	1,435	1,476	1,500
Gasoil	2,109	2,074	2,084

(1) Volumes reflected in the table include 100 percent of Hydro Texaco s volumes.

In 2003, Hydro s market share in the Swedish gasoline market declined by 0.7 percent mainly as a result of the discontinuation of agreements with Volvo dealers and their customers. These agreements are being phased out over a period of 5 years, from 2001 to 2005. To compensate for the loss in market share, Oil Marketing in 2003 entered into a deal with VW/Audi Sweden, allowing holders of VW/Audi credit cards access to Hydro and Uno-X stations. Bankcards, such as Eurocard and Visa, have also been introduced as valid means of payment at Hydro and Uno-X stations during the year.

Market share (%) (2003) [1]	Sweden	Norway [2]	Denmark [3]
Gasoline	9.9	20.2	16.8
Gasoil	14.3	16.0	17.5

(1) Includes 100 percent of Hydro Texaco.

(2) As of November 2003.

(3) As of October 2003.

Oil and Energy Government Regulation

The principal Norwegian legislation applicable to petroleum activities in Norway and on the NCS is currently the Norwegian Petroleum Act of 1996, a number of regulations issued under that Act, and the Petroleum Taxation Act of June 13, 1975.

The general principles underlying the Petroleum Act are that:

the Norwegian State is the owner of all petroleum resources in the ground;

the exclusive right to resource management is vested in the Norwegian State; and

the Norwegian State alone is authorized to award licenses with respect to petroleum activities.

Under the Petroleum Act, the Norwegian Ministry of Petroleum and Energy (the **Ministry**) has been delegated responsibility for resource management and administering petroleum activities on the NCS. The Ministry primarily implements petroleum policy through its power to award licenses, to approve operators field and pipeline development plans, and to approve gas sales contracts.

Norwegian Licensing System

Hydro normally participates in exploration and production activities with other parties, including private and state-owned oil and gas companies and other government entities. Contractual arrangements among partners are generally governed by an operating agreement, which provides that costs, production entitlements and liabilities are allocated according to each partner s respective percentage interest in a particular field or license area. Normally, one party is appointed as operator. Field activities are conducted under the overall supervision and control of an operating committee consisting of representatives from each participant in the field. This enables each of the non-operator partners to be involved in field development and operations.

The Petroleum Act and related regulations contain the main legal basis for the license system which regulates Norwegian petroleum activity. The most important type of license award under the Petroleum Act is the production license. A production license grants the holder an exclusive right to explore for and produce petroleum within a specified geographical area. The licensee becomes the owner of the petroleum produced from the field covered by the license, and, together with any partners, is jointly and severally responsible to the Norwegian State for obligations arising from petroleum operations carried out under the license. Notwithstanding the exclusive rights granted under the production license, the Ministry has the power to, in exceptional cases, permit third parties to carry out exploration in the area covered by a production license.

Production licenses are normally awarded through licensing rounds. The first licensing round for NCS production licenses was announced in 1965. Awards of licenses take place both through the principal licensing rounds (of which the 18th was announced for application in December 2003) and through separate rounds covering a defined area.

Licensees are required to submit a PDO to the Ministry for approval. In respect of fields of a certain size, the Norwegian Parliament (Storting) must accept the PDO before it is formally approved by the Ministry.

Production licenses are normally awarded for an initial exploration period, which is typically six years but can be for a shorter period or for a period of a maximum of ten years. During this exploration period, the licensees must meet a specified work obligation set out in the license. The work obligation will typically include seismic surveying and/or exploration drilling. If the licensees fulfill the obligations under the production license, they are entitled to extend the license for a period specified at the time when the license is awarded, typically 30 years.

For licenses granted after July 1, 1985, the Norwegian governmental authorities can delay development of a field indefinitely under the Norwegian Petroleum Act. Should development be delayed, licensees can apply for an automatic extension of the license term corresponding to the delay period. For licenses granted before July 1, 1985, the conditions in the specific license apply.

The Norwegian State may, if important public interests are at stake, direct licensees on the NCS to reduce their production of petroleum. From July 15, 1987 until the end of 1989, licensees were directed to curtail oil production by 7.5 percent. Between January 1, 1990 and June 30, 1990, licensees were directed to curtail oil production by 5 percent. In 1998, the Norwegian State resolved to reduce Norwegian oil production by about 3 percent, or 100,000 boed. In March 1999, the Norwegian State decided to further decrease production by 200,000 boed. In the second quarter of 2000, the reduction was brought back to 100,000 boed. On July 1, 2000, this restriction was removed. By a royal decree of December 19, 2001, the Norwegian government decided that Norwegian oil production should be reduced by 150,000 boed from January 1, 2002 until June 30, 2002. This amounted to roughly a 5 percent reduction in output.

Licensees may buy or sell interests in production licenses subject to the consent of the Ministry and the approval of the Ministry of Finance of the tax treatment. The Ministries must also approve direct or indirect transfers of interests in a license, including change of control of a licensee, if it would result in a new licensee s obtaining a decisive influence over the licensee. In most licenses there are no pre-emption rights in favor of the other licensees. The State s Direct Financial Interest (**SDFI**), or the Norwegian State, as appropriate, however, still holds pre-emption rights in most licenses.

A license from the Ministry is also required in order to establish facilities for transport and utilization of petroleum. When applying for such licenses, the owners, which are in practice licensees under a production license, must prepare a plan for installation and operation. Licenses to establish facilities for transport and utilization of petroleum will normally be awarded subject to certain conditions. Typically, these conditions require the facility owners to enter into a participants agreement. The ownership of most facilities for transport and utilization of petroleum in Norway and on the NCS is organized as a partnership or joint venture of a group of license holders, and the participants agreements are similar to the joint operating agreements entered into among the members of the partnership holding production licenses.

Licensees are required to prepare a decommissioning plan before a production license or a license to establish and use facilities for transportation and utilization of petroleum expires or is relinquished, or the use of a facility ceases. The decommissioning plan must be submitted to the Ministry no sooner than five and no later than two years prior to the expiry of the license or the cessation of the use of the facility, and must include a proposal for the disposal of facilities on the field. On the basis of the decommissioning plan, the Ministry makes a decision as to the disposal of the facilities.

The Norwegian government can require that licensees participate in the removal of offshore oil and gas installations (platforms, pipelines, etc.) on the NCS when production ceases or at the expiration of the concessions, whichever occurs first. The Norwegian government has the option to take ownership of a permanent offshore installation at no cost to it when a license expires, is surrendered or revoked or when the use of such installation has been terminated permanently. For onshore installations, compensation for expropriation has to be paid. In such cases, the Norwegian government would assume total responsibility for any well closure and decommissioning costs after this time, as well as removal costs of the installation. As a basis for estimating Hydro s future liabilities related to well closures, decommissioning and removal costs of the installation, Hydro s management evaluates Norwegian and international laws, treaties and practices, and the estimated value of recoverable oil and gas reserves that are expected to exist at the end of the various concession periods. See the discussion in Item 5. Operating and Financial Review and Prospects Hydro s Critical Accounting Policies Asset Retirement Obligations. The regulations allow for full deductibility in taxable income of dismantlement and removal costs.

Organization of Norwegian Gas Sales and Transportation

Until June 2001, gas sales contracts with buyers for the supply of Norwegian gas were required by Norwegian authorities to be concluded with the Gas Negotiation Committee, known as the *Gassforhandlingsutvalget* (**GFU**).

The structural changes taking place in the European gas market (see the discussion under EU Regulation EU Gas Directives and Related Regulatory Developments below) prompted the Norwegian State to consider whether changes to the gas resource management system on the NCS could contribute to further enhancing the efficiency of Norwegian gas producers. Accordingly, the Norwegian State, by a royal decree dated June 1, 2001, determined to abandon the GFU system and put in place a system whereby the individual licensees manage the disposal of their own gas. Adjustments in legislation, license agreements and other existing contracts necessary to implement the new system were finalized during 2002.

From January 1, 2003, the ownership of the Zeepipe, Franpipe, Europipe, Europipe II, Åsgard Transport, Statpipe, Oseberg Gas Transport and Vesterled joint ventures, and Norpipe AS was transferred to Gassled. As of February 1, 2004, the Kollnes gas terminal is also included in Gassled. With the approval of Gassled, Norwegian authorities have, by a royal decree of December 31, 2002, issued regulations for access to and tariffs for capacity in the upstream gas transportation system. Gassled has a uniform access regime, giving all natural gas undertakings and eligible customers who have a duly substantiated reasonable need of transportation a right to access the system under non-discriminatory, objective and transparent conditions. Access to the system is based on long-term and short-term transportation agreements. Gassled tariffs have been established through regulations established by the Ministry of Petroleum and Energy with effect from January 1, 2003.

Health, Safety and Environment Regulations

Petroleum operations in Norway are subject to extensive regulation with regard to health, safety and the environment (**HSE**). Under the Petroleum Act, which is in this respect administered by the Ministry of Labor and Government Administration, all petroleum operations must be conducted in compliance with a reasonable standard of care, taking into consideration the safety of employees, the environment and the economic values represented by installations and vessels. The Petroleum Act specifically requires that petroleum operations be carried out in such a manner that a high level of safety is maintained and developed in accordance with technological developments.

Licensees and other persons engaged in petroleum operations are required to maintain at all times a plan to deal with emergency situations. During an emergency, the Ministry of Labor and Government Administration may decide that other parties should provide the necessary resources, or otherwise adopt measures to obtain the necessary resources, to deal with the emergency for the account of the licensees.

The Norwegian Petroleum Directorate has adopted a wide range of regulations that set forth detailed requirements as to the HSE aspects of petroleum operations. In addition, a number of regulations adopted under other acts, such as the Working Environment Act of 1977 and the Pollution Act of 1981, apply to Hydro s operations. Violations of such regulations can lead to fines.

In Hydro s capacity as a holder of licenses under the Petroleum Act, it is subject to strict statutory liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of its licenses. This means that anyone who suffers losses or damages as a result of pollution caused by any of Hydro s NCS license areas can claim compensation from Hydro without needing to demonstrate that the damage is due to any fault on Hydro s part. If the pollution is caused by a force majeure event, a Norwegian court may reduce the level of damages to the extent it considers reasonable.

EU Regulation

Although Norway is not a member of the EU, it is a member of the European Free Trade Association (**EFTA**). The European Union and its Member States have entered into the Agreement on the European Economic Area (the **EEA Agreement**) with the members of the EFTA other than Switzerland. The main purpose of the EEA Agreement is to include the EFTA countries in the European Common Market. The EEA Agreement makes relevant provisions of EU legislation binding for the EFTA states other than Switzerland. Regulations and directives affecting Hydro are being adopted, in an increasing number, within the EU and then implemented in Norway under the EEA Agreement.

EU Emissions Trading Directive

The European Commission has adopted a directive (Directive 2003/87/EC) that seeks to establish an internal emissions trading system by January 1, 2005. The system would limit carbon dioxide emissions from a broad range of industries, including power generation, and place them within a regulatory framework. Under the directive, all producers with significant emissions of climate gases will be given an emissions permit for each year of production. Each Member State will develop a national allocation plan for such permits. The emissions trading system will increase a producer s costs if that producer does not achieve its targets. Additional costs would also be associated with the development of emissions reduction technology and trading tools. It is not clear how the directive will be implemented within the EEA.

EU Gas Directives and Related Regulatory Developments

Fundamental changes are now taking place in the organization and operation of the European gas market, with the objective of opening up national markets to competition and integrating them into a single EU internal market for natural gas. It is difficult to predict the effect of liberalization measures on the evolution of gas prices, but the main objective of the single gas market is to bring greater choice and reduced prices for customers through increased competition.

The EU Gas Directive of 1998 (Directive 98/30/EC, 1st Internal Gas Market Directive) established common rules for the transmission, distribution, supply and storage of natural gas. The main purpose of the directive was to require owners of natural gas pipelines to open up their transport systems, including systems within domestic markets, to customers, such as distribution companies and large industrial customers, in order to bring greater competition into the European gas market. The directive established rules relating to the organization and functioning of the natural gas sector, access to the market, the operation of systems, and the criteria and procedures applicable to the granting of authorizations for transmission, distribution, supply and storage of natural gas. The directive imposed a series of obligations on EU Member States and other states implementing the directive. In June 2002, the Norwegian Parliament (Storting) agreed to incorporate the directive into its legislation as part of the EEA Agreement.

48

On June 26, 2003, the European Parliament and the Council of the European Union adopted Directive 2003/55/EC (2nd Internal Gas Market Directive), providing for common rules for the internal market for natural gas. Directive 2003/55/EC repealed the earlier Directive 98/30/EC, which was viewed as taking the first relatively tentative steps toward the creation of an internal market for natural gas. Directive 2003/55/EC is not yet incorporated in the EEA Agreement. Directive 2003/55/EC is expected to provide the necessary structural changes in the regulatory framework to tackle the remaining barriers to the completion of the internal market. The directive provides for:

the right for all non-household gas customers to freely choose their supplier no later than July 1, 2004, with all customers to have this right by July 1, 2007;

third party access to transmission and distribution networks on the basis of published and ex ante regulatory approved tariffs;

the establishment of a regulatory authority in each Member State with a common minimum set of responsibilities;

legal unbundling of transmission and large and medium-sized distribution companies; and

access to storage facilities either on a negotiated or regulated basis.

In addition, the directive contains provisions relating to upstream pipeline networks. EU Member States are required to take the necessary measures to ensure that natural gas undertakings and eligible customers, wherever they are located, are able to obtain access to upstream pipeline networks, including facilities supplying technical services incidental to such access in accordance with the directive, except for the parts of such networks and facilities which are used for local production operations at the site of a field where the natural gas is produced. Access is to be provided in a manner determined by the EU Member State in accordance with the relevant legal instruments. EU Member States are to apply the objectives of fair and open access, achieving a competitive market in natural gas and avoiding any abuse of a dominant position, taking into account security and regularity of supplies, capacity that is or can reasonably be made available and environmental protection.

In February 2002, the European Gas Regulatory Forum, which is chaired by the EU Commission and made up of national regulators, network operators and users and gas consumers, agreed on a set of voluntary guidelines (referred to as the Guidelines for Good TPA Practice) on granting access to the gas transmission system. The guidelines were revised in September 2003. In a first compliance report presented to the Forum in October 2002, the EU Commission observed significant lack of compliance with the rules. In its second report presented at the Forum s meeting in September 2003, the EU Commission indicated a significant improvement in terms of compliance with the guidelines, but a continuing unacceptable level of non-compliance such that a level playing field in terms of access conditions to the gas transmission networks was far from being achieved. As a result, in December 2003, the EU Commission proposed a regulation providing for a set of basic principles to be respected as regards third party access (TPA) services to be offered by the system operators, capacity allocation and congestion management procedures, transparency requirements and tariff structures. The proposal also provides for detailed implementing rules to be contained in guidelines annexed to the regulation, which can be adopted and modified through a regulatory comitology procedure whereby the Commission submits a proposal to a committee consisting of representatives of the Member States, but in order for the proposal to be adopted, the committee has to deliver a favorable opinion on the proposal. If the opinion of the committee is negative, the proposal will be submitted to the Council, which may either adopt or reject the Commission s proposal.

On April 20, 2004, the EU Parliament in its first reading adopted the proposal with a number of amendments stating that the regulation, as amended, should be accepted without major amendments if more binding regulation is, indeed, needed. Network operators and the gas industry consider the regulation unnecessary, viewing the existing guidelines as sufficient to establish fair and transparent network access. Nonetheless, on June 10, 2004, the Energy

Council reached a political agreement on the proposed regulation. Once the agreed compromise text has been formally adopted in one of the upcoming Council sessions, it will be transmitted as the Council Common position to the European Parliament for second reading. The political agreement reached by the Council suggests the entry into force of the regulation on July 1, 2006 (one year before the EU gas market is scheduled to be completely opened up), whereas the guidelines providing the minimum degree of harmonization required to achieve the aim of the regulation may not be implemented before January 1, 2007.

Liberalization of European Electricity Markets

The EU electricity liberalization directive of 1996, to a large extent, left implementation of the deregulation process to the EU Member States. As a result, each country designed its own national market structure. These structures are not entirely compatible. The European Commission has acknowledged this problem on a number of occasions, indicating that action will be taken to remedy the situation. In 2003, the European Union enacted a number of provisions bearing on the European electricity market:

Directive 2003/54/EC sets forth common rules for the internal market in electricity. The directive establishes common rules for the generation, transmission, distribution and supply of electricity.

Regulation (EC) No. 1228/2003 addresses conditions for access to the network for cross-border exchanges of electricity. It attempts to establish fair rules for cross-border exchanges of electricity, thus enhancing competition within the internal electricity market, taking into account the specificities of national and regional markets. Realizing that objective will involve the establishment of a compensation mechanism for cross-border flows of electricity, the setting of harmonized principles on cross-border transmission charges, and the allocation of available capacities of interconnections between national transmission systems.

Taxation of Oil and Gas Production

Norway

Ordinary Taxes. Profits from Norwegian oil production are subject to Norwegian income tax at the rate of 28 percent. Revenue for tax purposes is based on market norm prices (as determined by a government-appointed board, normally on a quarterly basis but in recent years with large price fluctuations, on a monthly basis) for crude oil and on realized prices for gas and other primary products. The taxation of a company s income associated with its exploration and production activities on the NCS is assessed on a consolidated basis.

Investments in oil and gas production facilities are, in general, depreciated for tax purposes over six years using a straight-line method of depreciation (i.e., 16.66 percent per year). However, there is an exception for certain large-scale gas liquefaction facilities; such investments are depreciated over three years (i.e., 33.33 percent per year). Depreciation commences when expenditures are incurred. Deductions for exploration and other costs can be taken in the year such costs are incurred.

Any NCS losses may be carried forward indefinitely against subsequent income earned. Any onshore losses may be carried forward for 10 years. Half of the losses relating to activity conducted onshore in Norway may be deducted from NCS income subject to the 28 percent tax rate. Losses from foreign activities may not be deducted against NCS income. Losses from offshore activities are fully deductible against onshore income.

Special Petroleum Tax. A special petroleum tax is levied on profits derived from petroleum production and pipeline transportation on the NCS. The special petroleum tax is currently levied at a rate of 50 percent. The special petroleum tax is applied to relevant income in addition to the standard 28 percent income tax, resulting in a 78 percent marginal tax rate on income subject to the petroleum tax. The basis for computing the special petroleum tax is the same as for income subject to ordinary corporate income tax, except that onshore losses are not deductible against the special petroleum tax,

and a tax-free allowance, or uplift, has been granted at a rate of 5 percent of capital expenditures per year over a period of a minimum of six years (equal to a maximum total of 30 percent of the capital expenditures). The uplift is computed on the basis of the original capitalized cost, including capitalized interest, of offshore production installations. The uplift may be deducted from taxable income for a period of six years beginning in the year in which the capital expenditures are incurred. Unused uplift may be carried forward indefinitely. Special provisions apply to investments made prior to 1992. Deficits relating to NCS exploration and production activities can be carried forward indefinitely, both for ordinary and special petroleum tax purposes. Deficits incurred in 2002 and later can be carried forward with interest. The Ministry of Finance is authorized to issue guidelines on the interest rate.

As part of Revised National Budget passed in June 2004, the Norwegian government adopted changes to the Petroleum Tax Act which will be put forward in the budget for 2005. The tax-free allowance, or uplift, will be accelerated to 7.5 percent of capital expenditures per year over a period of four years. Furthermore the State will pay in cash the tax value of deficits connected to exploration in connection with the yearly tax assessment. The State will also pay in cash the tax value of deficits if a company ceases its activities on the Norwegian Continental Shelf. Changes also include simplification of tax-related conditions in relation to transfer of licenses, and changes in regulations regarding depreciation of investments in fields with life spans of less than six years. Larger flexibility in contracts between oil companies and contractors will be allowed.

Taxation Outside Norway

Hydro s international petroleum activities are covered by local tax legislation. The following provides a brief description of the relevant tax systems of the countries where Hydro has production. Hydro s Canadian production is covered by a tax/royalty regime, and its remaining international production is regulated by production sharing agreements (PSAs). Under a PSA, the host government typically retains the right to the hydrocarbons in place. The contractor under a PSA normally receives a share of the oil produced to recover its cost, and is entitled to an agreed share of the oil as profit in addition. Normally, the contractors carry the exploration costs and risk prior to a commercial discovery. Provisions are, to a large extent, negotiable and are unique to each block. All negotiated and bilateral provisions in the PSAs are subject to a confidentiality clause. The presentation of the taxation as such is, therefore, limited to the structure of the PSAs and to the official information involved.

Under some PSAs, all government take will be in the form of royalty and/or profit oil allocated to the state, whereas other PSAs also include an income tax element. Income is split between a cost oil share for the recovery of costs, and a profit oil pool for further split between the state and the contractors. Allocation of profit oil between the state and the contractor group may depend on many factors, for example, the development of the internal rate of the return of the project, the production rate or the accumulated production. As a result, a larger share will normally be allocated to the state during the life of the production period. Linear depreciation over the first four to five years in production is commonly used. Some PSAs allow for an uplift of the investments, which is included as an additional depreciation in the investment costs and thereby increases the cost recovery entitlement. Most PSAs allow unrecovered costs in one year to be carried forward for recovery in later years. The direct state participation in PSAs has varied, but seems to be more frequent in recently awarded blocks. Different variations as to financing of the direct state share are seen.

Some PSA regimes allow for consolidation of income from different developments in a block; other PSAs set a ring fence for tax purposes around each development. A ring fence around a development area means that the area is defined as a separate entity for tax calculation purposes, meaning that all development and production costs related to a development can only be recovered through income from the same development. One development may also consist of more development areas, all of which are ring fenced for tax purposes. The term development area in this respect may be a defined geological structure that may be produced from a common production facility.

Under a tax/royalty regime, the companies are granted licenses by the government to extract petroleum, and the state may be entitled to royalties, in addition to income tax based on the contractor s net income from the operations. The terms are, in general, not negotiable and are subject to legislative change.

Canada. The fiscal regime consists of both royalty and provincial/federal tax systems. There are generic royalty regimes for the Grand Banks and Scotian Shelf areas; however, the Hibernia and Terra Nova fields have unique royalty systems. An allowance of 25 percent of operating income is deductible for income tax purposes, and replaces the actual royalty paid. This allowance will be phased out by 2007 and replaced by full deductibility of royalties paid for income tax purposes. The East Coast royalty regimes are progressive with the size of the royalty depending on the field s economy and life cycle. Tax depreciation of facilities is 25 percent per year based on a declining balance method of depreciation. Exploration expenses may be fully written off. The combined Canadian federal and provincial tax rates are declining and will be reduced from the current 43 percent to 36 percent by 2007. Consolidation for tax purposes across all Canadian income is allowed within one legal entity (corporation); however, it is not allowed between separate legal entities.

Russia. The Kharyaga field is taxed based on a PSA. Gross income after deduction of the royalty is split in cost oil and a profit oil share. A 35 percent income tax is levied on the contractor share of the profit oil. The profit oil split is based on the project s cumulative internal rate of return.

Libya. The Mabruk field is taxed based on a PSA. Gross income after deduction of royalty is eligible as cost oil, and any surplus oil is allocated as profit oil. The profit oil is divided between the state and the contractors based on a sliding scale which is related to the daily production rate and a cumulative income to cost ratio. No further income tax is levied on the contractors share of the profit oil. The Murzuq field is taxed based on a PSA. The Libyan national company (**NOC**) is carried through the exploration phase and partly through the development phase, and then takes a certain ownership share of production. The net income, after deduction of NOC`s direct share, is used for cost recovery. Any surplus is split as profit oil between the state and the contractors, with a sharing principle as for the Mabruk development. No further income tax is levied. Consolidation of operations within the Murzuq blocks is allowed.

Angola. The producing fields, Girassol and Jasmim, are taxed based on the Block 17 PSA. Gross income is split in cost oil and a profit oil share. The contractor s share of the profit oil is based on the project s cumulative internal rate of return. A 50 percent income tax is levied on the contractors share of the profit oil. A ring fence around each development area in the block applies for tax purposes. Exploration costs, however, can be recovered from the entire block.

Taxation of Electricity

Ordinary Taxes (Norway)

Profits from hydroelectric power production are subject to ordinary Norwegian income taxation at a rate of 28 percent. Fixed assets are depreciated for tax purposes over 67 years or the concession period, if shorter (dams and tunnels); 40 years (machinery); and at a 5 percent declining balance (transmission and other electrical equipment).

A company s ordinary income tax for hydroelectric power plants is assessed on an aggregate basis and may be tax consolidated with other activities in Norway.

Surtax on hydroelectric power plants (Norway)

In 1996, a tax law was enacted in Norway for hydroelectric power plants effective from January 1, 1997. In addition to ordinary income tax, the major provision of the law called for the introduction of a surtax. The surtax rate is 27 percent. The surtax is assessed individually for each hydroelectric power plant (i.e., ring-fenced taxation). Unlike the ordinary income tax, finance costs are not deductible. Uplift is a special deduction in the net income computed as a percentage of the average tax basis of fixed assets (including intangible assets and goodwill) for a given year. The percentage, which is determined annually by the authorities, essentially provides for a certain return on capital that is not subject to surtax. The percentage used to calculate the uplift for 2003 was 9.7 percent.

Revenue for surtax purposes is based on market spot prices with certain exceptions. Revenues from power supplies used for a company s own industrial production facilities and from sales under certain long-term contracts are not subject to market spot price adjustments. As most of Hydro s hydroelectric production is used for its own production or sold under qualifying contracts, only a minor portion of the production is subject to taxation based on spot prices at the time of production.

Losses can be carried forward indefinitely or until the plant reverts to the Norwegian government. Losses carried forward are increased with interest.

A natural resource tax related to hydro-generated electricity became effective as of January 1, 1997. The rate for 2003 is NOK 0.013 per KWh. The tax is fully deductible from the ordinary income tax of the company.

HYDRO ALUMINIUM

Introduction and Overview

In March 2002, Hydro Aluminium solidified its position as one of the top three integrated aluminium companies in the world, in terms of volume of integrated aluminium products produced, by acquiring VAW, a major producer of primary aluminium, rolled products and other fabricated aluminium products based in Germany. Through this acquisition, Hydro Aluminium has become a full range aluminium company, expanding its range of products and activities in rolled products, extrusion and automotive offerings. In 2003, Hydro Aluminium s total revenues were NOK 69.2 billion compared to NOK 65.1 billion in the prior year.

Hydro Aluminium initiated cost reduction and improvement programs in 2001 and 2002, to be fully achieved in 2004. The objective of the programs was to achieve cost and earnings improvements of NOK 2.5 billion compared to the base-line combined cost and earnings level of Hydro Aluminium and VAW in 2001. The targeted accumulated cost savings and EBITDA improvements were achieved as of the end of 2003. This means that the full year effect for 2004 will be in line with the target of NOK 2.5 billion. The accumulated cost of the program was lower than originally estimated.

Hydro Aluminium s present organizational structure is as follows:

The graph below depicts Hydro Aluminium s aluminium operations, in terms of 2003 tonnage along the value chain.

Overview of Aluminium Industry

Aluminium is the third-most abundant element in the Earth s crust and the second-most used metal. The main properties that make aluminium a viable material include its light weight, strength, recyclability, corrosion resistance, durability, ductility and conductivity. Because of aluminium s unique combination of properties, the variety of aluminium products continues to grow.

Aluminium Smelting

The primary raw material for aluminium smelting is alumina, which is refined from bauxite. Bauxite deposits are most commonly found in tropical and subtropical regions of the world, such as Africa (Guinea), India, Jamaica, South America (Brazil, Surinam, Venezuela, and Guyana) and Australia. Bauxite is generally extracted by open cast mining. More than 100 million tonnes of bauxite are mined each year. Two to three tonnes of bauxite are required to produce one tonne of alumina; approximately two tonnes of alumina are required to produce one tonne of aluminium.

Alumina is dissolved in an electrolyte within a carbon- or graphite-lined steel container known as a pot. An electric current is passed through the electrolyte at low voltage, but very high current, typically 150,000 amperes, or as high as approximately 300,000 amperes with modern technology. The electric current flows between a consumable carbon anode (positive) and a cathode (negative), formed by the thick carbon or graphite lining of the pot. This splits the alumina into molten aluminium and carbon dioxide. The molten aluminium is periodically siphoned off into a holding furnace, then cleaned and cast into metal products such as extrusion ingot, sheet ingot, cast wire rod, primary foundry alloy, continuous cast coil, liquid metal and standard ingot. The molten aluminium is often blended with other metals, including iron, silicon, zinc, copper and magnesium, to form alloys with different properties.

On average around the world, it takes roughly 15.7 kilowatt-hours (**kWh**) of electricity to produce one kilogram of aluminium from alumina. Design and process improvements have progressively reduced this figure from about 21 kWh in the 1950s. In a modern smelter the electricity consumption could be approximately 13 kWh per kilogram. Nonetheless, aluminium smelting remains an energy-intensive process, which is why the world s smelters are located in areas that have access to abundant power resources. Many smelters are located in remote areas, where electricity is generated specifically for the aluminium plant. More than 50 percent of the energy used to produce aluminium supplied to the European market comes from hydro-electricity.

The smelting process is continuous. A smelter cannot easily be stopped or started. If production is interrupted by a power line failure of more than six to eight hours, the metal in the pots will solidify, often requiring an expensive rebuilding process.

Processing of Aluminium

Rolled Products

The aluminium rolling process changes the characteristics of the metal, making it less brittle and more ductile. Prior to rolling, the aluminium is in the form of a rolling sheet ingot that typically is up to 600 millimeters (**mm**) thick. The rolling sheet ingot is then heated to around 500 degrees Celsius and passed several times through a hot rolling mill. This gradually reduces the thickness of the metal to around 3-13 mm. The thinner aluminium is then cooled and transported to a cold rolling mill for further processing. There are various types of cold rolling mills, producing various types of rolled product with thicknesses as low as 0.006 mm in the case of foil. In general, the type of product depends on the alloy used, the rolling deformation and the thermal treatment used in the process. Rolling mills are controlled by very precise mechanisms and measuring systems. Rolled products include:

Foil typically less than 0.06 mm thick, foil is used mainly in the packaging industry (e.g., for foil containers and wrapping), for electrical applications and for building insulation.

Lithographic sheet typically of a thickness between 0.12 2.2 mm and with a high surface quality, lithographic sheet is used in the printing industry.

Sheet and strip typically between 0.06 and 3-4 mm in thickness, sheet and strip are widely used in the construction industry, in transport applications and in packaging.

Plate and shate over 3-4 mm in thickness, plate and shate are used in a number of applications, including airframes, military vehicles and structural components in bridges and buildings.

Extrusion

Aluminium cylinders, referred to as extrusion ingots, which are continuously cast from molten aluminium, can be extruded by heating the aluminium to around 450-500 degrees Celsius and pushing it through a die at great pressure to form intricate shapes and sections. The primary applications for extrusions include:

window frames, door frames and facades;

automotive applications like bumper beams, window and door frames and subframes;

transport segments such as trucks, trains and airplanes; and

machines, furniture and consumer durables.

Extruded products are sold in various forms, such as long lengths (e.g., six meters), cut to length, machined, formed, assembled in a component or module or as systems.

Casting

Aluminium can be cast into an infinite variety of shapes. Cast parts are used in a variety of applications including: light weight components for vehicles, aircraft, ships and spacecraft; general engineering components; architectural fittings; and high-tech products for office and home. Cast products can be produced using either sand casting (used for high production volume processing) or die casting.

Recycling

Anything made of aluminium can be recycled repeatedly. The recycling of aluminium requires only about five percent of the energy to produce primary metal. Scrap aluminium has significant value and commands good market prices. Many aluminium companies, including Hydro Aluminium, have invested in dedicated state-of-the-art secondary metal processing or remelt plants to recycle aluminium.

Industry Trends and Developments

Aluminium consumption in the Western World (i.e., the world, excluding China, the Commonwealth of Independent States (CIS) and Eastern Europe) has realized an average annual growth rate of approximately 2.7 percent over the last two decades. Industry analysts, such as Brook, Hunt and CRU, predict future growth in the Western World s consumption of aluminium in the next decade to be approximately three percent per year. On a global basis, the growth rate is expected to be about four percent mainly due to increasing consumption in China and the CIS.

Weak global economic conditions over the past few years have contributed to an oversupply situation. China s rapid increase in aluminium production has created increased uncertainty around the potential oversupply situation that could negatively affect international prices. China has traditionally been a net importer of aluminium. However, during 2002, China s capacity and production increased by about 30 percent while consumption grew by roughly 20 percent, and the country became a net exporter (approximately 250,000 tonnes). For 2003, net exports increased by an estimated 100,000 tonnes to a total estimated 350,000 tonnes. Over the longer term, China is expected to devote more or all of its aluminium production to internal consumption. However, if consumption and production in China fail to develop in parallel, it will almost certainly influence the metal pricing and the need for new capacity in the rest of the world. However, China has few natural advantages for primary production. China must import alumina, power sources are far into the country, and much of its power is coal-based. If alumina spot prices remain at levels similar to those in early 2004, this may reduce incentives for starting up additional new capacity in China in the short run. In addition, Chinese authorities announced a reduction of available credit for industrial development in China during the first quarter of 2004.

In 2003, growth in demand in Europe and in the United States, currently the world s largest aluminium consuming regions, was low to moderate. Total shipments of primary aluminium in the Western World increased approximately 4.6 percent (or 900,000 tonnes) compared to the prior year. New capacity resulted in increased production of about 540,000 tonnes. This was partially offset by net capacity idled of about 20,000 tonnes in 2003. In addition, there was an increase in net primary exports to the Western World from China of about 100,000 tonnes. CIS exports are estimated to have remained at the same level as in 2002. As a result, total reported and unreported inventories are estimated to have increased by approximately 300,000 tonnes.

Reported inventories of primary aluminium (defined to include London Metals Exchange (LME), International Aluminium Institute (IAI), Japanese merchant/consumer and other reported stocks) in the Western World increased approximately 100,000 tonnes in 2003 to a level of approximately 3.5 million tonnes.

Historically, stocks in the Western World have fluctuated considerably. From a level of approximately 1.5 million tonnes in the late 1980s, stocks peaked in 1993 at approximately 4.5 million tonnes and thereafter were rapidly reduced to approximately 2.6 million tonnes at the end of 1995. These changes mainly were attributable to the export of Russian metal to the Western World, and the subsequent production reduction implemented by producers. Since 1995, the annual fluctuations have been less than 500,000 tonnes. High and increasing stocks historically have had a downward impact on the aluminium price as illustrated in the following graph showing the LME 3-month price (i.e., the price quotation on the LME for delivery of metal three months from the date of quotation) and reported stocks estimated in days of consumption since 1994.

Primary aluminium is traded on the LME. The most common benchmark is the 3-month price. Prices are quoted on a daily basis, and normally reflect the market s expectations as to the future supply and demand balance, together with actual consumption and production data. Due to the liquidity in the LME market, hedge funds enter the market to varying degrees to capitalize on volatility in the prices. The LME price, which is stated in US dollars per tonne, serves as the main reference price for aluminium purchase and sale contracts worldwide. For medium to long-term alumina contracts, prices are also normally linked to the LME price of aluminium rather than alumina spot prices. For semi-fabricated products, a variety of contracts are used, both with respect to duration and pricing.

The graph below illustrates the annual average LME 3-month price of aluminium during the 1981-2003 period.

During the 1981-2003 period, the nominal LME 3-month price has reflected fluctuations based upon the factors described above and a marginal average annual increase. However, adjusting for the U.S. producer price index (PPI), the LME 3-month price, stated in real terms, declined at an average annual rate of approximately 1.2 percent during this period. Industry sources expect a decline in the real price of aluminium to continue in the long term.

Aluminium is used in a variety of applications in several industries. The table below reflects a percentage breakdown of the estimated levels of Western World consumption by the principal consuming industries in 2003, and the historic annual growth rates for these industries over the period of 1997 through 2003 (2003 reflecting forecasted figures).

Industry	**Percentage of Western World Consumption in 2003**	**Annual Growth Rates (1997-2003)**
Transport	29%	2.8%
Building & Construction	20%	0.8%
Packaging	18%	1.5%
Electrical	9%	1.2%
Consumer Durables	8%	1.7%
Engineering	8%	0.7%
Other	8%	1.6%

Source: Brook Hunt

Based on the historical data, the transport segment is expected to experience the most significant growth rates in the foreseeable future. The packaging, and building and construction, industries appear to be more mature industries, in terms of aluminium consumption, particularly in the United States and Western Europe.

During the last two to three years, there has been a prolonged economic downturn in the United States and Western Europe which has impacted the downstream aluminium industry.

The table below provides a breakdown of the 2003 production volumes in the principal aluminium producing regions and the percentage of the estimated percentage of total global production represented by each such region (2003 reflecting forecasted figures).

Region	Production Volume (in millions of tonnes)	Estimated Percentage of Total Global Production
North America	5.5	19.6%
South America	2.3	8.2%
Western Europe	4.1	14.6%
Eastern Europe (including Russia)	4.3	15.4%
Asia	8.2	29.3%
Oceania	2.2	7.9%
Africa	1.4	5.0%
Total	28.0	100.0%

Source: Brook Hunt

Industry Structure

Aluminium competes with substitution materials like steel, polyvinyl chloride (**PVC**), wood, glass, magnesium, etc. In addition, there is strong competition among the various aluminium producers, which have focused on reducing costs in order to retain or improve their competitive position. As a consequence, pressure has been put on uneconomic smelters using outdated technology, and some closures have been completed or announced. According to CRU, as of the end of 2003, approximately 2 million tonnes of capacity remained idle in the Western World, 1.5 million tonnes of which was located in the Northwest United States, due primarily to the high price of electricity in the regions where the production capacity is located. The likelihood and timing of the reactivation of any of this capacity is uncertain. In response to the competition, aluminium producers are seeking to expand their existing smelter units to capture economies of scale and investing in the development of cost-efficient plants (i.e., in areas with ample energy supplies and favorable energy prices). This is expected to continue in the foreseeable future.

Over the last decade the aluminium industry has consolidated significantly. Alcoa (based in the United States) has established itself as the number one integrated aluminium company through the acquisitions of Alumix (based in Italy), Inespal (based in Spain), Alumax (based in the United States) and Reynolds (based in the United States). Alcoa has also developed a significant position in alumina. Alcan (based in Canada), the number two integrated aluminium company, has acquired Alusuisse (based in Switzerland), and, in February 2004, Pechiney (based in France). Following the acquisition of Pechiney, Alcan s integrated aluminium operations are estimated to be approximately of a size comparable to that of Alcoa, though Alcan has recently announced its intended spin-off of substantially all of the rolled products businesses held by Alcan prior to its acquisition of Pechiney. Hydro Aluminium, following its acquisition of VAW in March 2002, has become the third-largest globally integrated aluminium company in terms of volume, with approximately 50 percent of the revenues of Alcoa and of a combined Alcan/Pechiney. Industry analysts expect that the consolidation activity within the aluminium industry will continue, although at a reduced scale compared to previous years.

In addition to the integrated companies mentioned in the preceding paragraph, there are several large companies whose focus is on upstream operations (i.e., bauxite, alumina or primary metal), such as BHP Billiton (based in Australia and the United Kingdom), Rio Tinto, through its subsidiary, Comalco Limited (Comalco) (based in Australia), and CVRD, through its subsidiary, Aluvale (based in Brazil). The Russian aluminium industry has consolidated into two companies, Rusal and Sual. Both companies focus on metal production in Russia, with minor downstream operations. Since the 1990s, China has emerged as a major producer of primary metal. The industry structure in China is still fragmented with many small- and medium-sized companies, of which Chalco has evolved as the most significant.

Downstream, there are a few major independent semi-fabricating producers outside the large integrated systems. In finished products, the structure is much more fragmented.

Hydro Aluminium s Competitive Position

Hydro s acquisition of VAW has provided a balance between Hydro Aluminium s primary upstream production and downstream activities. The downstream activities added to Hydro Aluminium s business activities through the VAW acquisition have complemented and broadened Hydro Aluminium s product portfolio, contributing to such activities achieving a critical size. For example, Hydro Aluminium has evolved from a rather marginal to a leading producer in the European rolled products business (annual sales of flat rolled products expanded from 133,000 tonnes in 2001 to 893,000 tonnes in 2003). According to the November 2003 edition of CRU s Aluminium FRP Quarterly report, Hydro Aluminium s Rolled Products sub-segment is now the world s third-largest producer of flat rolled products, measured by volume. Hydro Aluminium s management estimates that flat rolled products represent roughly half of the global aluminium consumption.

Hydro Aluminium now has important European positions within high margin rolled products segments such as lithographic (printing) plates and foil. Each of Hydro and Alcan has a 50 percent ownership interest in Aluminium Norf GmbH (**AluNorf**), which is the world s largest hot rolling mill according to CRU s Rolled Mills Equipment Profiles 2000 report. As a result of Alcan s acquisition of Pechiney, the European Commission has required that Alcan divest, within a year, a combination of assets including either Pechiney s Neuf-Brisach rolling mill in France or Alcan s 50% share in AluNorf in Germany. In terms of capacity, either divestment will represent between 13-14% of the consumption in the European market. Alcan s announced spin-off plan for substantially all of the rolled products businesses held by Alcan prior to its acquisition of Pechiney contemplates its interest in AluNorf being shifted to the new company created in connection with the transaction. Alcan announced that the spin-off would achieve its regulatory divestiture requirements from the European Commission.

Hydro Aluminium s management believes the composition of its portfolio has several benefits compared with other integrated aluminium companies. The benefits enable Hydro to maximize high margin product offerings with less capital employed. This is accomplished by or as a result of:

- sourcing approximately 50 percent of the alumina needed to produce aluminium through medium- to long-term contracts, rather than through ownership interests;
- sourcing a similar tonnage of metal from scrap, other ingot sources and alliance partners (see Strategy Leverage Metal Supplier Concept below) as Hydro Aluminium produces from its own electrolysis production; and
- the composition of its downstream product mix. Hydro Aluminium has a higher proportion of extrusion production than rolled products production when compared with other integrated aluminium companies. Extruded products offer attractive margins and require less capital invested per tonne than rolled products.

Strategy

Hydro Aluminium s strategy has multiple components, reflecting its integrated aluminium operations.

Ensuring Alumina Supply

Hydro Aluminium has, over the last decade, based its supply of alumina on a combination of alumina production from facilities in which it has an equity interest and a portfolio of medium- to long-term contracts. Through completion in 2003 of the expansion (to approximately 2.4 million tonnes} of the Alunorte alumina plant in Brazil, in which Hydro Aluminium holds a 34 percent interest, the equity portion of its alumina supply has increased and now covers approximately 50 percent of the needs of its smelter system. Hydro Aluminium has never been an operator of alumina plants, but has instead prioritized its capital and management resources in areas in the value chain where Hydro Aluminium could add greater value. In general, over the last decade there has been a favorable alumina supply

situation, with the exception of a few short periods of tight supply. Consequently, it has been possible for Hydro Aluminium to capitalize on its financial strength to enter into favorable contracts. During 2003 and in early 2004, the alumina market has been tight and spot prices have risen. For Hydro Aluminium, this had little impact due to its combination of supply from equity interests and contracts. While this situation may continue for several years, Hydro Aluminium s management believes the risk for a long-term tightening of supply of alumina in the market is limited, since there is remaining potential to expand current capacity with moderate investments. Accordingly, Hydro Aluminium will continue to pursue an alumina strategy based on sourcing a substantial part of its needs through medium- to long-term contracts.

Restructure Smelter Portfolio; Improve Relative Cost Position

Hydro Aluminium, like the other leading integrated aluminium companies, plans to increase the share of its production being produced at larger smelters. Based on approved projects, Hydro Aluminium expects to increase its share of production being produced by smelters with a capacity of more than 250,000 tonnes per year from 27 percent in 2002 to approximately 46 percent by the end of 2006. The expansions in primary production are being made in plants where the existing infrastructure supports a larger capacity. This can be done at a lower investment level than a corresponding new or greenfield investment. Expansion of an existing facility improves the operating cost position of the plant, thereby improving the overall long-term cost position.

Hydro Aluminium has taken active steps to increase its metal production and improve its average cost position. The annual production capacities of the Søral smelter (located in Norway; Hydro s share is 49.9 percent) and the Slovalco smelters (located in Slovakia; Hydro s share is 20 percent) have been expanded by approximately 32,000 tonnes and 34,000 tonnes, respectively, and now have an annual primary aluminium capacity of approximately 160,000 tonnes each. Hydro s equity share of the increase in combined production due to the expansions is approximately 20,000 tonnes. The fully owned Sunndal smelter (in Norway) is in the process of being expanded to an annual primary aluminium capacity of 330,000 tonnes. The expansion is scheduled to be completed in the autumn of 2004. In 2002, Hydro approved participation in the expansion of the Alouette smelter in Canada. Total annual primary aluminium production capacity will increase by 307,000 tonnes to 550,000 tonnes in 2005, making Alouette the largest aluminium smelter in North America and among the world s lowest cost smelters. Hydro s ownership interest and share of the production is 20 percent. Including other smaller projects, these expansions of primary aluminium production capacity will increase Hydro Aluminium s total annual primary aluminium capacity to approximately 1.7 million tonnes by 2005, from the level of nearly 1.5 million tonnes in 2003.

Even with Hydro s efforts to improve the relative cost position of its smelter system through continuous improvement and reduced cost within existing capacity and expanding capacity at low cost smelters, Hydro s Norwegian smelters face challenges in reaching acceptable cost levels. Approximately 30 percent of production costs in these smelters relate to direct and indirect labor. A combination of higher wages, social benefits, shift schedules, higher manning for support functions and higher prices for purchased services in Norway result in a cost disadvantage for these smelters. As a result, on May 7, 2004, Hydro s Board of Directors decided to recommend to the Corporate Assembly a plan aimed at reducing annual costs by NOK 350 to NOK 400 million. The plan will require a reduction of manning by about 800 employees in the Norwegian plants. The reduction in manning is expected to be completed by the end of the first quarter of 2005.

Leverage Metal Supplier Concept

In view of the high investment costs associated with new smelter capacity, since the 1990 s Hydro Aluminium has pursued a multi-sourcing strategy, which it refers to as the metal supplier concept. This strategy, focusing on building a strong market position in the metal products market, has been based on three primary components:

develop alternative metal sources through commercial alliances and other agreements;

better utilize Hydro Aluminium s casthouse capacity; and

expand Hydro Aluminium s remelt activities.

Hydro Aluminium has entered into several long-term commercial alliances and agreements that further its strategy of developing and leveraging the metal supplier concept with limited asset investment. Under one of these agreements, Hydro Aluminium will participate in upgrading the aluminium casthouse at Rusal s Sayanogorsk smelter, located in southern Siberia. Upon completion of the first stage of the construction, anticipated in the first half of 2004**,** Hydro Aluminium will be supplied with 80,000 tonnes per year of high quality extrusion ingot under the terms of a technology and remarketing agreement. The second stage, to follow a few years later, will further increase casting capacity to 160,000 tonnes. Hydro Aluminium has also entered into a new long-term agreement with Talum in Slovenia, under which Talum will supply Hydro Aluminium with 70,000 tonnes of foundry alloy products per year during 2004-2010.

Focused Growth in Selected Markets Downstream

Rolled Products

Following the acquisition of VAW, Hydro Aluminium is the number two producer in the European rolling industry; management estimates that it has a market share of approximately 18 percent. Hydro Aluminium has a strong product portfolio including foil, lithographic and automotive sheet products. The acquisition of VAW has improved Hydro Aluminium s asset base, bringing into Hydro a high level of technical competence in the work force and a portfolio of high quality products. Hydro Aluminium s rolled products strategy is to focus on growth in selected segments (such as lithography, a product segment for which management has recently approved an expansion of German capacity of lithographic plate by approximately 75,000 tonnes), while at the same time continuing to work on operating improvements. Several initiatives have been launched to improve the Rolled Products sub-segment s financial results, addressing selling, general and administrative costs and direct production costs. Plant specialization will also be pursued to improve efficiency. Following completion of a number of projects in 2003, the level of capital expenditures is expected to go down somewhat and be at approximately the same level as depreciation.

Extrusions

Hydro Aluminium currently holds a leading position in the European soft-alloy extrusions market with a market share estimated by Hydro Aluminium s management to be approximately 14 percent. Hydro Aluminium is a leader in the building systems market in Europe, with its position having been bolstered by the acquisition of the French-based company, Technal, in 2002. The acquisitions of the former Wells Aluminum (based in the United States) in 2000 and VAW in 2002 have strengthened Hydro Aluminium s position in the North American extrusions markets. In South America, the plants in Brazil and Argentina have been established as important footholds that will provide bases for future developments. In parallel with this growth, Hydro Aluminium has focused on improving the performance of its extrusions operations under challenging market conditions in order to place itself in a better position to capture new growth opportunities. Hydro Aluminium intends to continue to expand its product offerings in the global extrusions markets through selected forward integration into product refinements and value-added services to improve margins and volume. Further, Hydro Aluminium will seek to increase its presence in these markets through organic growth and selective acquisitions.

Automotive

Hydro Aluminium is actively engaged in meeting the needs of the automotive market, which has become the principal source of the growth in demand in the aluminium industry during the last ten years. On average, approximately 25 percent of Hydro Aluminium s sales in tonnes of primary metal have been ultimately destined for the automotive sector, either as customers of Hydro Aluminium s own semi-fabricated and finished products or through other tier suppliers using Hydro Aluminium s foundry alloys to make automotive parts. Hydro Aluminium s product portfolio in Europe includes primary foundry alloys, precision tubing and crash management systems. Hydro Aluminium also engages in the production of aluminium engine blocks and cylinder heads in Europe and Mexico. In the United States, precision tubing products are an important part of Hydro Aluminium s product offerings to the automotive industry.

In 2003, Hydro Aluminium s Automotive sector focused on improving its profitability by streamlining production processes to reduce costs. The short- to medium-term strategy is to continue to focus on selected products and leverage the investments made to improve profitability.

Improvement of Operational Performance throughout the Organization

The VAW acquisition had the immediate benefit of expanding Hydro Aluminium s portfolio of plants with relatively attractive costs given the scale of several of the smelters and rolling mills acquired. Furthermore, it provided opportunities to capture the synergies available from a larger scale of operations. This included streamlining the sales, general and administration processes, reducing manning, and sharing best production and other practices to enhance productivity and reduce fixed and variable costs. Hydro Aluminium dedicated significant time and attention in 2002 to the successful integration and extraction of synergies from the acquisition. These efforts continued with full force in 2003 to ensure that the entire potential was realized.

Following the completion of the VAW acquisition, Hydro Aluminium undertook the rapid integration of the two companies activities. To capture the synergies associated with the acquisition, Hydro Aluminium launched a program encompassing internal benchmarking to identify and implement cost savings through the introduction of best practices work processes across the units and the optimization of production systems. Together with the improvement programs already in place, these programs contributed to cost reductions throughout the system.

Even before the VAW acquisition, Hydro Aluminium had initiated cost reduction and improvement programs throughout its various segments. In 2002, Hydro Aluminium achieved its combined cost and staff reduction targets for these and the VAW-synergy programs. This resulted in aggregate savings of approximately NOK 1 billion, compared to the base-line cost level in 2001 for the combined Hydro Aluminium and VAW businesses. Closure of the primary magnesium production in Norway yielded NOK 424 million of the total savings. Additional programs resulted in the remaining savings. Staff reductions in 2002 totaled 534 employees in the primary magnesium operation and 708 employees associated with other cost reduction initiatives. Hydro Aluminium increased its total savings and improvements targets for its improvement programs in the fourth quarter of 2002 by NOK 400 million to a total of NOK 2.5 billion by the end of 2003, to be achieved with full effect for 2004. As of the end of 2003**,** Hydro had achieved the cost saving and improvements targets, including an aggregate manning reduction of over 1,700 employees compared to the 2001 base-line level. This means the full year effect for 2004 will be in line with the target of NOK 2.5 billion. Accumulated restructuring and rationalization costs related to these programs were NOK 1,166 million, NOK 397 million less than originally estimated.

In 2004, Hydro Aluminium will maintain a strong focus on identifying and capturing additional cost reduction opportunities throughout the value chain.

Hydro Aluminium s Operating Sub-Segments

METALS

Hydro Aluminium s Metals sub-segment (Metals) consists of the two sectors, Primary Metal and Metal Products. The Metals sub-segment encompasses Hydro Aluminium s upstream activities, principally the production and sale of primary aluminium produced in Hydro Aluminium s smelters. Metals activities also include the processing of scrap into high quality products for the mid- and downstream markets, all aluminium and raw materials trading activities, Hydro Aluminium s high purity business and magnesium operations.

Primary Aluminium Production

Hydro Aluminium produces its primary aluminium at 12 wholly or partly owned primary aluminium smelters. Most smelters operated at full capacity during 2003. Production at the smelters during the three most recent years are reflected in the table below:

Aluminium production (tonnes)	**2003**	**2002[1]**	**2001**
Primary Aluminium			
Karmøy	271,000	273,000	272,000
Årdal	215,000	206,000	206,000
Sunndal [2]	210,000	153,000	156,000
Høyanger	74,000	73,000	71,000
Søral (Hydro s 49.9 percent share) [3]	79,000	67,000	62,000
Slovalco (20 percent share) [4]	27,000	22,000	18,000
Rheinwerk	221,000	173,000	
Elbewerk	69,000	48,000	
HAW (33.3 percent share)	43,000	33,000	
Kurri Kurri	156,000	122,000	
Tomago (12.4 percent share)	59,000	45,000	
Alouette (20 percent share)	49,000	38,000	
Total primary aluminium production	1,473,000	1,253,000	785,000
Average price primary aluminium (U.S.$/tonne per LME 3-month price)	1,428	1,365	1,454

(1) Includes VAW volumes from the VAW acquisition date of March 15, 2002.

(2) The Sunndal smelter is in the process of being expanded to an annual primary aluminium capacity of 330,000 tonnes. The 2003 production volume reflects the partial completion of the expansion.

(3) The annual production capacity of the Søral smelter has been expanded by approximately 32,000 tonnes. The 2003 production volume reflects Hydro s share of that expansion.

(4) The annual production capacity of the Slovalco smelters has been expanded by approximately 34,000 tonnes. The 2003 production volume reflects Hydro s share of that expansion.

Emission standards, established by the Norwegian Pollution Authority in accordance with the Oslo and Paris Convention regulations (see Environmental Matters Oslo and Paris Commission (OSPAR) below), require primary aluminium production facilities using the Søderberg technology in the Høyanger and Årdal primary aluminium plants to be closed by the end of 2006. Hydro has decided that investments to replace this capacity will not be made. The resulting closures will reduce Hydro Aluminium s annual primary aluminium production capacity by 72,000 tonnes by, at the latest, 2007.

Raw Materials

Alumina

Hydro Aluminium has secured a part of its long-term alumina requirements for its primary metal production through investments in alumina plants. In 2003, following the expansion at Alunorte, a Brazilian alumina refinery, approximately 50 percent of its alumina requirements for primary metal production was provided by such investments.

Hydro Aluminium s major alumina investment is its 34 percent participation in Alunorte. After an expansion of the plant in 2003, its capacity has reached approximately 2.4 million tonnes, enabling

Hydro Aluminium to secure access to 810,000 tonnes of alumina per year. In the third quarter of 2003, Hydro decided to participate in a further expansion of Alunorte. This planned expansion will increase capacity to approximately 4.2 million tonnes in 2006, providing Hydro Aluminium with a total of approximately 1.4 million tonnes of alumina annually. Hydro Aluminium believes that Alunorte s cash operating costs are significantly below the alumina industry s world average. As a result of this investment in Alunorte, Hydro Aluminium will maintain approximately 50 percent coverage of its alumina needs through its equity investments, taking into account the higher production arising from planned primary metal expansions.

Hydro Aluminium also has a 35 percent equity interest in the Alpart alumina refinery in Jamaica, which has an annual production capacity of approximately 1.5 million tonnes. In late May 2004, Hydro decided to exercise its right of first refusal, provided under the Alpart partnership agreement between Hydro Aluminium and Kaiser Aluminum, to acquire the remaining 65 percent interest. On June 3, 2004, the US Bankruptcy Court for the District of Delaware ordered that Kaiser proceeds with the sale of its interests in and related to Alpart to Hydro. Immediately after this purchase has been completed, Hydro will sell this 65 percent interest to the Swiss-based Glencore AG on the same terms and conditions as those governing Hydro s acquisition of the interest. Following the completion of these transactions, Alpart will change from being operated by a managing partner to having independent management. Both Hydro and Glencore will be represented on Alpart s ultimate governing body, the Executive Committee. The agreement with Glencore also contemplates optimization of bauxite mining activities between Alpart and Windalco, an alumina refining company in Jamaica (with an annual production capacity of approximately 1.35 million tonnes), which is 93%-owned by Glencore. The changes in ownership of Alpart, as well as the optimization of bauxite mining activities, are subject to approval by the Jamaican government. Hydro and Glencore have also entered into a memorandum of understanding under which each company will explore the possibility of closer cooperation and utilization of synergies between Alpart and Windalco.

In addition to the equity interests in alumina production capacity mentioned above, Hydro Aluminium has a number of short-, medium- and long-term purchase contracts to secure alumina for its own smelters and trading activities. These contracts typically have pricing formulas based upon a percentage of the LME price.

In June 2003, Hydro Aluminium and Comalco signed one of the largest alumina supply contracts in the history of the aluminium industry. Under the agreement, Comalco will supply Hydro Aluminium with 300,000 tonnes of alumina in 2005 and 500,000 tonnes of alumina annually from 2006 through 2030.

Energy

Energy represents about 25 percent of the operating costs associated with primary aluminium production. Hydro Aluminium has negotiated long-term contracts for its Norwegian smelters. Much of this energy is purchased from or through Hydro Energy. Hydro Energy produces, in its own hydroelectric generating plants, electricity amounting to more than 70 percent of the requirements of Hydro Aluminium s Norwegian primary aluminium smelters. More than 95 percent of the electricity needed to operate the Norwegian smelters in 2004 is covered by medium to long-term supply contracts. Certain long term supply contracts with Statkraft expire in the summer of 2006. Hydro has already entered into new contacts with Statkraft replacing these contracts through year 2020. Compared with the expiring contracts, the new pricing structure will increase energy costs starting in the second half of 2006. Long-term availability of electricity at predictable prices is considered a prerequisite for the further development of the Norwegian operations particularly since Nordic spot market prices can be highly volatile.

The smelters outside Norway source energy under contracts with local producers. For the large smelters in Canada and Australia, Hydro has entered into long-term contracts. The current contracts for the German smelter system are scheduled to expire at the end of 2005. New contracts will need to be negotiated before that time. Hydro owns 33.33 percent of the German aluminium smelter, Hamburger Werk GmbH (HAW). HAW has an electricity supply contract through the end of 2005 with Hamburger Electricitätswerke AG (HEW). During the fourth quarter of 2003, HEW gave notice of an early termination of the existing electricity supply contract effective September 30, 2004. The current market price for power is considerably higher than the contract price. Negotiations for an acceptable settlement, including a new electricity price for the period from the beginning of October 2004 to the end of December 2005, have not yet reached a conclusion. If these negotiations do not reach a satisfactory agreement, it is likely that litigation will be initiated. Should it not prove possible to obtain power at an acceptable price, the ultimate consequence may be the closure of HAW.

Anodes

Anodes are used and consumed in the smelting process. Most of Hydro Aluminium s smelters produce their anodes at their own on-site facilities.

Remelt Activities

Hydro Aluminium has established remelt plants for conversion of scrap metal into extrusion ingot in all major European markets. Facilities are located in Norway, Luxembourg, the United Kingdom, Germany, Spain and France, as well as at the primary metal plants in Norway, Germany and Slovakia.

Scrap is sourced from internal and external customers, and in addition standard ingot is used as input material. The main customers are internal and external extrusion plants.

Sales and Distribution; Trading Activities

Most of Hydro Aluminium s own production of aluminium cast house products is sold in Western Europe and in the United States to semi-fabricating plants like extruders, rollers and wire mills, as well as foundries. The main consumer areas are transportation, construction and packaging. The major consuming countries in Europe are Germany, France, the United Kingdom, Italy and Spain. Most of the aluminium is sold in the form of value-added products such as extrusion ingot, rolling ingot, wire rod and foundry alloys.

Hydro Aluminium has consistently strengthened its commitment to customer service and increased the efficiency of its production systems. Metals regional market teams have competencies within technical and commercial service, research and development, logistics, contract administration and scrap conversion. To enhance its existing service level, Metals implemented a program in 2001 called Hydro Billet Plus. The aim of the program is to reward the Metals sub-segment s most important customers and customers who wish to increase their business volume. This service concept includes a web-enabled tool allowing customers to improve their understanding of commercial and LME price risk and to optimize their production system.

To support the metal supplier concept, Hydro Aluminium engages in trading of aluminium and related raw materials, mainly alumina. Trading is a natural extension of Hydro s internal sourcing activity. Trading contributes to optimizing capacity utilization within Hydro s own system as well as reducing logistics costs by sourcing both internally and externally from a variety of sources. Aluminium trading activities consist of physical metal purchases and sales, as well as trading on the LME. In 2003, Hydro s metal traders sold externally 705,000 tonnes of primary aluminium products, compared to 478,000 tonnes in 2002. The main trading product is standard aluminium ingot, which is also the global aluminium product on which price quotations on the LME and other metal exchanges are based. Hydro Aluminium has a small alumina trading activity that has been profitable during the last five years.

Alumina is often used in combination with metal trading/sourcing activities, for example, by supplying a third party smelter with alumina and receiving metal as compensation.

High Purity Aluminium

As a result of the VAW acquisition, Hydro Aluminium produces and sells high purity aluminium products which are mainly used in the electronics industry in products like electrolytic capacitors or semiconductors. High purity products have an aluminium content of between 99.98 to 99.9999 percent. The producers of high purity aluminium are quite concentrated, with two producers in Europe, four in Japan, two in China and one in Russia. Hydro Aluminium s management has estimated that global production in 2003 was approximately 70,000 tonnes. Through its three production sites in Japan, Norway and Germany, Hydro Aluminium sold about 12,000 tonnes in 2003.

Magnesium

The magnesium industry in the Western World comprises only a few producers of primary magnesium. The International Magnesium Association (IMA) predicted that worldwide shipments for 2003 would reach approximately 388,000 tonnes compared with its estimate of actual 2002 shipments of 365,000 tonnes. Based on the latest statistics available (2002), China and CIS shipments represented about 57 percent of the total. Increased quantities of Chinese magnesium available in Western markets over the past several years have resulted in significant downward pressure on magnesium prices.

Hydro Aluminium has a primary (electrolytic) magnesium plant in Becancour, Canada, that produced approximately 50,000 tonnes in 2003**.** In addition, it has remelt operations in Norway, Canada, Germany and China with a combined remelting and recycling capacity of approximately 50,000 tonnes.

ROLLED PRODUCTS

Hydro Aluminium s Rolled Products sub-segment (Rolled Products) is centered in Europe, with rolling mills in Germany, Norway, Spain and Italy, as well as a foil rolling mill in Malaysia that provides a foothold in Asia. Production capacity includes a 50 percent share in the AluNorf hot rolling mill in Germany, which in 2003 provided almost 610,000 tonnes to Rolled Products. Most of Hydro Aluminium s entitlement to the products from AluNorf is further processed in the nearby plant in Grevenbroich before being delivered to customers. Grevenbroich is the center (from the standpoint of technology, best competence and capacity) of Rolled Products foil and lithographic sheet operations.

The table below shows the ownership interest and sales volume per main site in Rolled Products production system.

Site	Ownership Percentage	2003 Sales Volume [1] (in thousands of tonnes)
Grevenbroich, Germany	100	506
Hamburg, Germany	100	131
Slim, Italy	100	78
INASA, Spain	100	22
AISB, Malaysia	81	18

Karmøy, Norway	100	58
Holmestrand (including Alucoat), Norway	100	80
Total, excluding internal sales and wire rod		893
AluNorf, Germany	50	610(2)

(1) Excludes intra-company shipments, except volume cited for AluNorf.

(2) 100 percent of shipments from AluNorf are intra-company.

In 2003, Rolled Products had external shipments of 893,000 tonnes, mainly to the European market, where Hydro Aluminium s management estimates it holds a market share of approximately 18 percent.

Rolled Products, like the rest of the rolling industry, produces a wide variety of products for different industries and with different product margins. Important success factors within the rolling industry are optimizing the product mix and capacity utilization, as well as streamlining the production system. Because the rolling industry is capital intensive, high capacity utilization (volume) is important to reach an acceptable fixed cost per tonne. This must be balanced with optimizing margins and product mix. There are large differences in margins between different products, with the most attractive products limited in terms of demand.

Rolled Products customer base includes customers in the packaging, automotive, transport, building, engineering, electrical and printing industries. A major part of Rolled Products sales functions is organized centrally along the product lines. Such organization enables optimization of sales, planning and production in Rolled Products total system.

Rolled Products consists of four business units serving different market segments, which in 2003 had the following sales volumes to external customers:

Unit	2003 External Sales Volumes (in tonnes)
Lithography	128,000
Foil	143,000
Strip	562,000
Automotive	60,000
Total	893,000

In 2003, Rolled Products management estimates that the Lithography business unit had an average annual growth in sales volume of about 14 percent, outpacing management s estimate of five to seven percent growth in general lithography demand in the market. Rolled Products management attributes this primarily to Rolled Products focus on quality and customer service. Hydro Aluminium s Lithography business unit is well positioned to continue to expand its customer base and meet increased competition. Both on the demand and supply side, the lithography market is characterized by a high degree of concentration.

Rolled Products Foil business unit has endeavored to leverage its market position in Europe to respond to the needs of global customers for a global supplier with a local presence. Within important foil segments such as liquid packaging, management estimates Rolled Products is the global leader (in terms of volume). In 2001, Rolled Products acquired a 65 percent ownership interest (increased to 81 percent in 2002) in a Malaysian rolling mill to serve as a base for supplying customers in the Asian region. Living standards in Asia are rising, hence packaging needs are growing rapidly and foil is an important packaging material.

The Strip unit s business is characterized by higher volumes and lower margins compared to the other units within Rolled Products. For this business, high capacity utilization and production efficiency are particularly important. The current strategy is to optimize the combined production and market system of Rolled Products to realize the full potential.

Automotive flat rolled products are expected by Hydro Aluminium s management to have higher growth than other flat rolled products in Europe. Principally using its existing asset base, Rolled Products is expanding its flat rolled product range from non-visible applications to applications that are visible (referred to as the body-in-white market) on a finished manufactured vehicle. Body applications are expected to be a strong, growing market segment due to auto manufacturers continued desire to reduce weight. CRU projects that auto body sheet consumption will approximately double in size from 2002 to 2007 in Europe. As the surface requirement demands a special quality, a new finishing line has been constructed in Grevenbroich, Germany.

Most of the metal required for the production in Rolled Products is delivered from Metals. In addition, process scrap from Rolled Products customers and scrap collected from the market is, together with Rolled Products own process scrap, remelted and casted to rolling ingots in the casting facilities of Rolled Products. Supplies from Metals are priced on an arm s-length basis with reference to the LME price. External supplies of rolling ingot to Rolled Products are approximately 14 percent of its total requirements.

EXTRUSION AND AUTOMOTIVE

The Extrusion and Automotive sub-segment of Hydro Aluminium consists of three sectors: Extrusion, Automotive and North America. Their main products are extruded aluminium profiles, used primarily in the building and construction markets and the transportation segment.

Extrusion

The Extrusion sector (**Extrusion**) is primarily focused on the European market. Extrusion is Europe s largest soft alloy extruder of aluminium, in terms of volume, based upon estimates of Hydro Aluminium s management. Extrusion also has operating entities in Brazil and Argentina, and has a minority participation in a South African entity. In 2003**,** Hydro Aluminium s total production of extruded products (i.e., from all sectors) was 569,000 tonnes.

Extrusion mainly consists of general extrusion activities and its Building Systems unit. With respect to its general extrusion activities, Extrusion supplies custom-made general extrusions of soft alloy aluminium, surface treatments such as anodizing and powder coating, fabrication, components and finished products. Building Systems supplies complete design and solution packages to metal builders, enabling them to supply both the commercial and residential building markets with products, such as facades, partition walls, doors and windows, as well as other building applications through its three main brands: Technal™, Wicona™ and Domal™.

In January 2002, Extrusion enhanced its position through the acquisition of Technal, a French-based manufacturer of aluminium building systems. The Technal acquisition augmented Extrusion s general extrusion operations through the addition of extrusion capacity in France and by doubling Building Systems volumes.

Automotive

The Automotive sector (**Automotive**) comprises all of Hydro Aluminium s precision tubing, structures and shape-casting businesses worldwide. In the last few years, Automotive has followed a strategy of continuous growth in order to strengthen its position as a supplier to the highly demanding automotive industry. Automotive is currently introducing several new products with start-up of new production lines.

Hydro Aluminium s management believes that Automotive is the leading supplier of aluminium extrusion-based applications within crash management (e.g., bumper beams, crash boxes, engine cradle components) in Europe. Automotive is also involved in crash management in North America and has increased its U.S. bumper production in 2003 based upon existing contracts. The sector has received safety awards for crash management systems supplied to several vehicles.

Automotive s precision tubing unit produces applications used primarily within radiators, fuel coolers and liquid lines. This unit has a significant market presence in Europe, North America and South America. The unit also supplies part of the Chinese market through its joint venture plant in China. Hydro Aluminium has announced that it will start construction of its first wholly owned precision tubing plant in China, to deliver precision drawn tubing, multi-port extrusions and extruded tubular profiles used in automotive heat transfer applications. Hydro will break ground in the first half of 2004. The investment costs are estimated to be NOK 150 million, and will create about 140 new jobs in

Suzhou.

Through the acquisition of VAW, Automotive became the owner of VAW s casting business and technology. The sector is one of a few independent (i.e., not affiliated with an automotive manufacturer) suppliers in Europe of aluminium cylinder heads, engine blocks and inlet manifolds. In June of 2004, Hydro announced its intended closing of the aluminium cylinder head production plant located in Leeds in the U.K. as a result of an unfavorable competitive environment/position. Production is planned to cease toward the end of 2004 or in early 2005. Production of turbo cylinder heads for GM will be relocated to Hydro s plant in Gyør, Hungary.

Through its competence in technology and in cooperation with Daimler Chrysler, Automotive has developed the first aluminium high performance, high volume V6 diesel engine block.

North America

The North America sector (**North America**) comprises all non-automotive extrusion and remelt plants in the United States. Through the acquisition of Wells Aluminum in 2000 and VAW s North American extrusion assets in 2002, the sector has increased its size as an extrusion company in the North American market, with seven extrusion plants and four stand-alone component manufacturing fabrication facilities, including one in Mexico.

The North America sector produces a broad range of extruded shapes, and provides finishing services, for numerous end markets. The sector has a leading position within the North American drawn tube market for demanding applications in office imaging products and health care. It also supplies extrusion-based products to the transportation, building and construction, and consumer durable markets.

The sector operates six remelters, including its new remelter in Commerce, Texas (which started operations in 2002), representing one of the largest remelting systems in the United States. The remelt network produces extrusion ingot and offers cost-efficient remelt solutions to the North American sector s customers.

The U.S. market has proven to be more volatile than the Western European market. The North American extrusion market fell by approximately 21 percent from 2000 to 2001, and remained flat in 2002. In 2003, the American Aluminum Association estimated that extrusion shipments fell by one percent compared to 2002. By comparison, estimated consumption in the Western European market declined by about four percent from 2000 to 2001 and a further one percent in 2002. In 2003, estimated Western European consumption increased approximately one percent compared with 2002.

North America s operations were particularly affected by the trailer market segment, which experienced the largest decline, starting in 2001. The North America unit took a number of actions to respond to the drop-off in demand. In 2002, it closed the former VAW headquarters in Florida and an office in Kentucky. In 2002, it also closed a Georgia extrusion plant, transferring existing contracts to other facilities to improve press utilization and profitability.

Environmental Matters

Hydro Aluminium is subject to a broad range of environmental laws and regulations in each of the jurisdictions in which it operates. These laws and regulations, as interpreted by relevant agencies and the courts, impose increasingly stringent environmental protection standards regarding, among other things, air emissions, the storage, treatment and discharge of wastewater, the use and handling of hazardous or toxic materials, waste disposal practices, and the remediation of environmental contamination. The costs of complying with these laws and regulations, including participation in assessments and remediation of sites, could be significant.

Aluminium production is an energy-intensive process that has the potential to produce significant environmental emissions, especially air emissions. Carbon dioxide, a greenhouse gas, is a major emission from aluminium production. The European Commission has adopted a directive that would limit carbon dioxide emissions from a broad range of industries and establish an internal emission trading system. So far the aluminium industry has not been included in the emission-trading directive.

In the European Union and other countries, various protocols address trans-boundary pollution controls, including the reduction in emissions from industrial sources of various toxic substances such as poly-aromatic hydrocarbons, and the control of pollutants that lead to acidification. Carbon dioxide regulation has been the subject of significant political debate in the United States, but thus far the United States has decided not to ratify the Kyoto Protocol. U.S. legislation regarding carbon dioxide emissions could be enacted in the future. Such legislation could have an effect on costs, but until such legislation is passed, it is not possible to provide a meaningful estimate. The United States has an extensive regulatory program to control other air emissions from aluminium facilities, including hazardous air pollutants.

The European Union has a framework of environmental directives integrated into the Water Framework Directive (2000/60/EC) regarding discharges of dangerous substances to water. The implementation of the directive has started in Europe and must be finalized by 2009. The manner in which this directive will be interpreted and enforced cannot be predicted. However, based upon the information currently available, Hydro Aluminium s management does not believe it will have a material negative impact on its business. The United States has a regulatory permit system limiting the discharge from facilities to water bodies and publicly owned treatment works, as well as regulations to prohibit discharges of hazardous substances into groundwater.

Hydro Aluminium has a number of facilities that have been operated for a number of years by Hydro Aluminium or have been acquired by Hydro Aluminium after operation by other entities. Subsurface contamination of soil and groundwater has been identified at a number of such sites and may require remediation under the laws of the various jurisdictions in which the plants are located. Hydro Aluminium has reserved amounts for sites where contamination has been identified that it believes to be sufficient to pay the cost of remediation under existing laws. Because of uncertainties inherent in making such estimation, it is at least reasonably possible that such estimates could be revised in the future. In addition, contamination may be determined to exist for additional sites that could require future expenditure. Therefore, actual costs could be greater than the amounts reserved.

Hydro Aluminium believes that it is currently in material compliance with the various environmental regulatory and permitting systems that affect its facilities. However, the effect of new or changed laws or regulations or permit requirements, or changes in the ways that such laws, regulations or permit requirements are administered, interpreted or enforced, cannot be predicted.

Oslo and Paris Commission (OSPAR)

The Oslo and Paris Convention for the Protection of the Marine Environment of the North-East Atlantic has resulted in new emission levels for the aluminium industry related to the prevention of marine pollution, which are scheduled for implementation by all signatories to the Convention before 2007. Emission standards, established by the Norwegian Pollution Authority in accordance with the Oslo and Paris Convention regulations, require primary aluminium production facilities using the Søderberg technology in the Høyanger and Årdal primary aluminium plants to be closed by the end of 2006.

Integrated Pollution Prevention and Control

Under the EU Directive on Integrated Pollution Prevention and Control 96/61/FC, from October 2007 existing industrial installations will require national emission permits, which will be based on best available techniques (**BAT**) for pollution prevention and control. The directive already applies to all new installations. The European Commission has issued a guidance document relevant for the aluminium industry; Best Practice Reference (BREF) for the Non-Ferrous Metals Industries (2001). This is also relevant for the European Economic Area (EEA) and the Norwegian authorities will start a process whereby the emission permits will be changed accordingly, to be effective by, at the latest, 2007. Hydro Aluminium s production facilities currently meet the EU requirements and are positioned to comply with future expected requirements from the Norwegian authorities.

Climate Gases

EU directive 2003/87/EC issued on October 13, 2003, establishes a scheme for trading greenhouse gas emission allowances. The directive introduces mandatory trading of carbon dioxide from combustion plants and certain specified industry sectors effective as of January 1, 2005. The intention with the directive is to broaden it to include more gases and sectors as of January 1, 2008. EU Member States national authorities are currently setting up National Allocation Plans and registries. This EU directive is also believed to be relevant for the EEA, although it is not clear at this time how the directive will be implemented in the EEA. The aluminium industry is not expected to be included before, at the earliest, 2008. Hydro Aluminium s operations are positioned to comply with the new requirements, when applicable.

The directive could impact production costs at facilities in the EU indirectly through increased electricity costs.

Government Regulation

EU Aluminium Tariffs

The EU has implemented an import duty of six percent on non-EU imports of aluminium. The Eastern European countries that joined the EU on May 1, 2004 became subject to this duty, though inventories of aluminium located in these countries prior to the date of accession are exempt from duty. The EEA, of which Norway is a member, is not subject to such duty for aluminium metal produced in the EEA.

The import duty has been subject to debate within the European Union and it is not possible to predict whether it will be maintained. The World Trade Organization (**WTO**) round of negotiations on tariff and non-tariff barriers on industrial products may ultimately lead to a reduction, if not elimination, of aluminium tariffs. However, it is likely that changes arising from WTO commitments will not be phased in until 2006 or 2007, at the earliest. Thus, the WTO negotiations are not expected to have a substantial impact on Hydro Aluminium in the near future. The Federation of Aluminium Consumers in Europe, which represents some aluminium consuming industries in the EU, has been pressing the EU authorities for the removal of the EU s aluminium tariff for the past several years. The EU Commission has, however, resisted a unilateral reduction of the tariff.

Energy Taxation

An EU directive on the taxation of energy products became effective on January 1, 2004. The directive will expand the minimum tax system of energy products from mineral oils to all energy products, including coal, coke, natural gas and electricity. This could affect Hydro Aluminium by making energy inputs, including electricity, more expensive as a result of the tax. However, countries subject to the directive will be authorized to apply reduced rates or tax exemptions on certain products or energy uses, such as energy used in reduction processes, renewable energy sources or heat produced in combined generation installations. Accordingly, aluminium producers in the European Union may be able to secure tax relief depending upon how the individual countries implement the directive and its reductions and exemptions.

72

OTHER ACTIVITIES

Other activities include Hydro s petrochemicals operations (Hydro Polymers), Treka AS, Hydro Pronova and Hydro Business Partner. Other activities include products and businesses outside of Hydro s core business areas. Other activities are managed together with the objective of developing their long-term business potential as part of Hydro or outside of the Hydro Group.

Other activities also includes Industriforsikring a.s., Hydro s captive insurance company.

PETROCHEMICALS

Since late 1996, the global petrochemicals industry has faced an oversupply situation. Competitive pressures have led to alliances, restructurings and mergers within Europe (e.g., the merger of Royal Dutch/Shell s and DEA s petrochemicals businesses in Germany and BP s purchase of Veba Oel from E.On). The consolidation has been motivated, in large part, by the objectives of achieving economies of scale, lowering operating costs and increasing unit margins. The consolidation in the part of the petrochemical industry in which Hydro is active, mainly PVC in Europe, has been less extensive.

Hydro s petrochemicals business has responded to increased competition by lowering fixed, recurring and variable costs and increasing asset productivity through, among other things, de-bottlenecking and staff reductions of roughly 58 percent (including activities sold) compared to 1996 levels. In early 2004, Hydro decided to discontinue the previously announced divestment of its petrochemicals business.

For the foreseeable future, the competitive environment for world commodity petrochemicals and polymers is expected to be characterized by a widening cost gap between the petrochemical/polymer producers that are integrated into raw materials and those that are not backwards integrated. In view of market conditions, Hydro s petrochemicals business will continue to focus on operational improvements through the establishment of best practice teams to ensure the transfer of knowledge in both operations management and process technology. The efficiency enhancement process is expected to entail further staff reductions, improved supply contracts, increased productivity and improved margin management.

Hydro s petrochemicals business is involved in all stages of production of the plastic raw material, PVC, also known as vinyl, and its intermediate products, ethylene, chlorine and vinyl chloride monomer (**VCM**). Hydro Polymers is the largest PVC supplier in the Nordic countries, with a market share of approximately 70 percent. In the United Kingdom, Hydro Polymers ranks first with approximately 38 percent of the market. The PVC industry in Europe is relatively fragmented, reflecting the industry s development on a national, rather than a European, basis. Hydro has an advantage in being backward integrated into ethylene and having close proximity to other Scandinavian countries and the United Kingdom, as well as long-term strategic relationships with customers in these markets.

Hydro has a 29.7 percent interest in Qatar Vinyl Company Ltd., which operates a petrochemical plant at Mesaieed Industrial City, Qatar. The plant has an annual capacity of 230,000 tonnes of VCM, 175,000 tonnes of ethylene dichloride and 290,000 tonnes of caustic soda. In China, Hydro has a 31.8 percent interest in Suzhou Huasu Plastics Co., Ltd., which produces PVC film and has a suspension PVC (**S-PVC**) capacity of 120,000 tonnes per year. Hydro also has a 26.2 percent interest in CIRES, a PVC resin and compound manufacturer in Portugal.

Raw Materials and Production

Hydro has a 50 percent ownership interest in an ethylene cracker through Hydro s joint venture interest in Noretyl AS. The cracker is integrated with Hydro s chlorine and VCM production facilities

73

located at Rafnes, in Norway. The production efficiencies inherent in an integrated production process contribute to higher margins compared to margins of competitors that rely on purchased ethylene. Petrochemicals has a secure supply for most of its remaining ethylene (44,100 tonnes). In June 2004, Hydro decided to carry out a project to streamline the production process at Noretyl, increasing total capacity to 557,000 tonnes of ethylene per year. The total cost of the project is estimated to be NOK 600-700 million.

Petrochemicals production (in tonnes)

	2003	2002	2001
Base Products			
VCM	575,000	540,000	591,000
Caustic Soda	281,000	262,000	279,000
Polymers			
S-PVC	507,000	458,000	465,000
P-PVC	81,000	70,000	72,000
Total Polymers	588,000	528,000	537,000
PVC Compounds	129,000	128,000	143,000

Average Market Quoted Prices in Northwest Europe

	2003	2002	2001
Ethylene /tonne delivered	522	518	616
VCM Spot export fob US$/tonne	452	451	345
S-PVC /tonne delivered	683	714	656

Hydro manufactures PVC at the following plants: Hydro Polymers AS (Porsgrunn, Norway), Hydro Polymers AB (Stenungsund, Sweden) and Hydro Polymers Ltd. (Aycliffe, United Kingdom). The Nordic sites produce S-PVC and paste PVC (**P-PVC**) while the U.K. site produces S-PVC for external sale and mixing with additives to generate PVC compounds in a variety of grades to meet customer specifications. VCM is produced at Hydro s Rafnes and Stenungsund plants.

Ethylene feedstock for the Rafnes facility is supplied by long-term contracts for NGLs from a number of North Sea fields for approximately 50 percent of the required volumes. The remaining needs are covered by spot purchases. The share of NGL purchased under long-term contracts will increase from the autumn of 2005. Price formulas are linked to naphtha and therefore indirectly to oil prices. As such, oil prices are an important driver of ethylene costs. Petrochemicals share of ethylene produced at Rafnes in 2003 was 220,000 tonnes. Hydro Polymers AS and Borealis entered into an agreement with Statoil and Petoro, under which it will purchase their ethane production at Kårstø, for a period up until 2015. This, together with the Noretyl project described above, should help enhance the long-term competitiveness of the ethylene plant.

The total production of chlorine in 2003 was approximately 250,000 tonnes. Chlorine feedstock in excess of Hydro s own production is covered by medium-term and spot purchases (approximately 95,000 tonnes). Plant closures in Europe reduced the chlorine supply in 2002. In March 2003, Hydro s Board of Directors approved a plan to build a new 130,000 tonne chlorine plant at Rafnes, at a cost of approximately NOK 1,000 million. The project is expected to be completed in the autumn of 2005.

At present, Hydro Polymers transports raw materials and intermediates among its plants in Rafnes, Stenungsund and Aycliffe. Increased efficiency and lower transportation costs could be achieved by an improved balance between input (raw materials) and output (final product) streams at the individual plants.

Sales and Description

PVC and PVC compounds are mainly sold by Hydro s own sales organization. Distribution is mainly by truck. Pipe grade S-PVC is considered to be a commodity product, while there is considerable product and price differentiation in other S-PVC applications. P-PVC accounts for about 7 percent of the total PVC market. P-PVC is traditionally considered to be a specialty product influenced only to a limited extent by S-PVC price developments.

Caustic soda, a by-product of chlorine production, which is used by a variety of industries such as in paper and pulp, alumina and soap production, is sold to customers in Europe and North America mainly through Hydro s own sales organization. Distribution is by vessel, rail or truck. In addition to its own production, Hydro trades moderate quantities of caustic soda in the same markets.

TREKA AS

Treka AS is a publicly held Danish company listed on the Copenhagen stock exchange, in which Hydro has a 68.8 percent interest. After the sale of major parts of the former KFK throughout 2002 and 2003, the remaining operational activities in Treka consist of the BioMar fish feed operations. Due to difficult conditions in the fish farming industry, BioMar undertook write-downs of goodwill, provisions for accounts receivable and bad debt in the total amount of NOK 570 million in 2003. A potential divestment of the BioMar activities was announced and initiated, but did not result in any offers on acceptable terms. Treka s board has, therefore, decided to terminate the sales process.

PRONOVA

Hydro Pronova was set up to develop and commercialize activities outside of Hydro s core areas.

Through its subsidiary Biocare, Hydro Pronova has developed a highly concentrated Omega-3 pharmaceutical product, Omacor , for treatment of post-myocardial infarction (Post-MI) and hypertriglyceridemia. In the first quarter of 2004, Hydro sold 80.1 percent of its interest in Biocare for NOK 165 million.

Pronova sold its Swedish subsidiary, Carmeda AB, in 2003. Further, Hydro Formates AS, which had also been part of Pronova, was transferred to Yara in connection with the Demerger. Following these developments, the bulk of Pronova s portfolio has been disposed of and Hydro intends to phase out the unit.

HYDRO BUSINESS PARTNER

Hydro Business Partner (**HBP**) was formed as a sector for service and support functions in the beginning of January 2000. HBP is organized in two primary functional units: Production and Facility Services and IS Services and Business Support Services. HBP has made substantial contributions to cost reductions in the units it serves. Long-term agreements have been entered into with Yara for the supply of maintenance and IS services, among others.

INDUSTRIFORSIKRING

Industriforsikring a.s., a captive insurance company, is a wholly-owned subsidiary of Hydro. Industriforsikring provides property damage, business interruption, cargo and third party liability insurance coverage for subsidiary companies of the Hydro Group. Industriforsikring also provides similar coverage for several related companies where Hydro owns a substantial equity interest. Industriforsikring has an extensive reinsurance program and has maximum exposure per policy varying from NOK 5 million for cargo insurance up to NOK 110 million for third party liability claims exceeding NOK 1,500 million. The operations of Industriforsikring are not substantial to Hydro s overall business and the Company s exposure to uninsured risk is not material.

ITEM 4.C. ORGANIZATIONAL STRUCTURE

The following significant subsidiaries, as that term is defined by applicable rules of the SEC, are included in the Hydro Group:

Company Name	Country of Incorporation	Proportion of ownership Interest*
Norsk Hydro Produksjon AS	Norway	100 percent
Hydro Aluminium AS	Norway	100 percent
Hydro Aluminium Deutschland GmbH	Germany	100 percent

* Ownership percentage reflects proportion of voting power.

ITEM 4.D. PROPERTY, PLANTS AND EQUIPMENT

The Group s rights to oil and gas located on the Norwegian Continental Shelf, mainly in the North Sea, are among its most important assets. See Item 4.B. Business Overview Oil and Energy Exploration, Development and Production for information with regard to reserves and sources of oil and gas and Item 4.B. Business Overview Hydro Oil and Energy Oil and Energy Government Regulation with regard to the Norwegian government s authority to increase its participation in the development of certain oil and gas fields and other regulatory matters.

The Group s major production plants in Norway are located at Porsgrunn (PVC), Rafnes (petrochemicals), Karmøy, Årdal, Sunndalsøra, Holmestrand and Høyanger (aluminium). The Group owns clear title concessions to hydroelectric power stations with a generating capacity of 2.7 TWh per year. Generating capacity of approximately 8.7 TWh is operated under concessions from the Norwegian government that will expire without compensation in the period between 2018 and 2052. Hydro s principal aluminium production facilities abroad are located in Austria, Belgium, Canada, China, Denmark, France, Germany, Hungary, Italy, Luxembourg, Poland, Portugal, Australia, Spain, Sweden, the United Kingdom and the United States. Hydro has an interest in a retail gasoline and fuel oil marketing network through an affiliated company in Denmark and Norway and wholly owned operations in Sweden. Hydro also participates in alumina refineries in Jamaica and Brazil, and an automotive parts casting plant in Mexico.

Virtually all of the Group s properties are owned by the Company s subsidiaries, except certain facilities in the oil and gas, hydroelectric and petrochemicals businesses which are jointly-owned with other companies. All major facilities of the Group are insured in line with customary industry practices.

Hydro is subject to changing environmental laws and regulations that in the future may require Hydro to modernize technology to meet more stringent emissions standards or to take actions for contaminated areas. See Note 21 to the Consolidated Financial Statements for a description of expenses and accruals relating to corrective environmental measures for 2003 and preceding fiscal years. There were no environmental measures, implemented voluntarily or required by law, which had a significant effect on the utilization of Hydro s main production facilities in 2003.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

ITEMS 5.A.-D. OPERATING RESULTS; LIQUIDITY AND CAPITAL RESOURCES; RESEARCH AND DEVELOPMENT, PATENTS AND LICENSES; TREND INFORMATION

The comparative discussion of Hydro s financial condition and results of operations as of and for the years ended December 31, 2003 and 2002, as well as information regarding Hydro s material commitments for capital expenditures as of year-end 2003 and Hydro s research and development policies for the three-year period ended December 31, 2003 is included in the following discussion.

2003 Compared with 2002

Financial review

Amounts in NOK million	**2003**	2002	2001
Operating revenues	**171,782**	167,040	152,999
Operating costs and expenses	**(147,524)**	(147,199)	(131,916)
Operating income before financial items and other income	**24,258**	19,841	21,083
Non-consolidated investees	**1,229**	33	566
Financial income (expense), net	**201**	1,935	(762)
Other income (expense), net	**(1,212)**	219	578
Income before taxes and minority interest	**24,476**	22,028	21,465
Income tax expense	**(13,937)**	(13,278)	(13,750)
Minority interest	**148**	15	177
Income before cumulative effect of change in accounting principle	**10,687**	8,765	7,892
Cumulative effect of change in accounting principle	**281**		
Net income	**10,968**	8,765	7,892
Earnings per share before change in accounting principle (NOK)	**41.50**	34.00	30.50
Earnings per share (NOK)	**42.60**	34.00	30.50

This discussion should be read in conjunction with the information contained in the Company s consolidated financial statements and the related notes included in this annual report.

Summary of key developments in 2003

Hydro s net income in 2003 was NOK 10,968 million (NOK 42.60 per share) compared with NOK 8,765 million (NOK 34.00 per share) in 2002. The result reflects overall improvements in Hydro s main business areas compared to the prior year. Market conditions have been good for many of the Company s products, although the weaker US dollar had a negative influence on all business areas. The positive developments also reflected the efficient implementation of improvement programs.

The most substantial improvement related to a significant increase in oil and gas production, together with somewhat higher oil and gas prices. For 2003, total oil and gas production was 530,000 boe per day representing an increase of 10 percent compared with 2002.

Improvement programs carried out by Aluminium generated considerable savings for the year. Programs initiated in 2001 and 2002 were completed and are expected to achieve targeted reductions of annual costs of NOK 2.5 billion, with full effect from 2004, compared to the combined cost level of the VAW and Hydro Aluminium businesses in 2001. The accumulated cost of the program was NOK 1,166 million (NOK 176 million for 2003) which was NOK 397 million below the original cost estimate. Markets for semi-fabricated aluminium products were weak during the year, but there are some signs of improvement. The competitive position for Hydro s European aluminium smelters is challenging and the Company plans to continue working to improve the cost position of these plants.

The fertilizer business also improved its results due to higher product prices and productivity gains. A strong development in nitrogen fertilizer prices led to significantly higher results for the year, despite negative currency effects and higher energy costs.

The Ormen Lange project is on schedule. The Plan for Development and Operation (PDO) was submitted to the Norwegian authorities at the beginning of December 2003. The field is expected to produce significant new volumes of gas, which are planned for sale in the UK gas market. The field is expected to come on stream in autumn 2007.

Hydro s Extraordinary General Meeting resolved January 15, 2004 to demerge Hydro Agri. The new company is named Yara International ASA, and has been listed on the Oslo Stock Exchange since March 25, 2004. Yara has approximately 7,600 employees and is headquartered in Oslo. Yara has the right to use Hydro s former viking ship logo, which is an important fertilizer brand. Every Hydro shareholder as of the listing date received one Yara share for each Hydro share held. In the demerger, 80 percent of the Yara shares were distributed to Hydro s shareholders. Hydro sold the remaining 20 percent of the Yara shares in an offering following the completion of the demerger which occurred on March 24, 2004.

Operating Results

The change in operating income and the most important items affecting the change follows:

Amounts in NOK million	
Operating income 2003	24,258
Operating income 2002	19,841
Change in Operating Income	4,417
Prices and currency, E & P[1])	1,870
Margin including currency effects[2])	(695)
Volume	3,580
Fixed costs	(326)
Depreciation	(945)
Production and exploration costs, E & P[1])	1,540
Infrequent items and restructuring costs	245
Trading and unrealized LME effects, Aluminium	475
New / disposed business	135
Other	(1,462)
Total change in operating income	4,417

1) Exploration and Production
2) Including negative variance for elimination of unrealized gain/loss on internal electricity contracts of NOK 729 million for 2003

Operating income for Oil and Energy in 2003 amounted to NOK 21,143 million, approximately 33 percent higher than in 2002. Production of oil and gas increased by 10 percent compared to 2002. The positive effect of higher oil prices in US dollars during 2003 was offset somewhat by the decline in the US dollar/Norwegian kroner exchange rate. However, oil prices measured in Norwegian kroner were 4 percent higher than in the previous year. Exploration costs of NOK 1,577 million were charged to income in 2003, a reduction of approximately NOK 2 billion compared with 2002.

Operating income for Aluminium in 2003 was NOK 2,456 million, approximately 45 percent higher than in 2002. However, excluding new business and infrequent items, operating income for Aluminium declined NOK 143 million. Margins, excluding the effect of hedge programs, were approximately NOK 560 million lower compared with 2002. Margins improved for Rolled Products and Extrusion but were weaker for Metals and Automotive. During 2003, aluminium prices measured in Norwegian kroner fell by seven percent compared with 2002. As a result, margins were substantially weaker in Metals compared to 2002 reducing results by approximately NOK 760 million. The decline was offset by contribution from hedges and higher trading results. However, higher fixed cost and depreciation from ramp up of new production capacity and unrealized losses on LME contracts, more than offset the savings from improvement programs and the contribution from increased volumes.

Operating income for Agri was NOK 2,800 million, NOK 593 million higher than the year before. Higher fertilizer prices measured in US dollars improved operating income by approximately NOK 2,600 million. Price gains were partly offset by the negative effect of increased raw material and energy costs of approximately NOK 1,200 million. The strengthening of European currencies against the US dollar affected operating income negatively for 2003 by approximately NOK 750 million. Total sales volumes for Agri were unchanged for the year as a whole. Sales of own produced products were up six percent for the year. Due to the strong increase in prices, many customers made their purchases early in the season. However, prices are expected to decline somewhat and high volumes sold in the first half of the fertilizer season may impact sales volumes negatively in the remainder of the season (first half of 2004).

Operating income relating to Other Activities reflected losses on bad debts and write downs of goodwill and intangible assets amounting to approximately NOK 570 million relating to the fish feed operations included in Treka.

Corporate and Eliminations incurred an operating loss of NOK 1,727 million in 2003 compared to a loss of NOK 24 million in the previous year. The loss primarily reflected higher pension costs and the elimination of unrealized gains on internal power purchase contracts. In addition, the 2003 result included costs of NOK 130 million linked to the demerger of Hydro Agri, charged during the fourth quarter.

Costs relating to pensions and related employers social security costs, charged to Corporate and Eliminations amounted to approximately NOK 1,146 million compared to NOK 312 million in 2002.

The increase in 2003 primarily reflected increased pension obligations and a reduction in plan assets during 2002. The increase in 2003 also included a non-recurring charge of roughly NOK 230 million, including employers social security costs, due to a settlement loss incurred in connection with a reduction in the number of members in certain pension plans in Norway. The reduction in the number of members resulted from workforce reductions and early retirement programs.

Hydro Energy is responsible for ensuring the supply of electricity for the company s own consumption, and has entered into power purchase contracts in the market and sales contracts with other units in the Group. These contracts are recognized at market value in Hydro Energy. For other Hydro units, the related internal purchase contracts are regarded as normal purchase contracts and are not recognized at market value. During the year, the estimated market value of the external power purchase contracts decreased with a corresponding increase in the contract value of internal sales contracts for Hydro Energy. The elimination of the unrealized gains included in Hydro Energy s results relating to internal sales contracts resulted in a charge to Corporate and Eliminations of NOK 141 million compared with a gain of NOK 588 million in 2002. The total negative variance relating to these contracts for 2003 was NOK 729 million. The power purchase contracts have a duration of up to 10 years and can result in significant unrealized gains and losses, impacting the results in future periods. This will depend on trends in forward prices for electricity and changes in the contract portfolio.

Earnings from non-consolidated investees amounted to NOK 1,229 million for the year compared to NOK 33 million in 2002. A currency loss of NOK 461 million relating to alumina operations in Brazil influenced the result in 2002, compared to a currency gain of NOK 218 million in 2003. Excluding these effects, earnings improved by NOK 517 million for the year primarily due to stronger results from non-consolidated investees which are part of the Agri business area reflecting high ammonia and urea prices.

Other income (expense), net for 2003 reflected a loss of NOK 1,212 million. The loss included a charge of NOK 2,207 million resulting from new Norwegian tax regulations relating to the removal costs for oil and gas installations on the Norwegian continental shelf. In accordance with earlier regulations, removal costs could not be deducted when calculating taxable income. Instead, the Norwegian state assumed a portion of the removal costs by means of a special removal grant for each license calculated on the basis of the average tax rate incurred by the participating companies over the license period. The new rules permit removal costs to be deducted from taxable income. The amendment resulted in a charge in the second quarter representing the estimated value of expected grants. The charge had no cash effect. At the same time, a deferred tax asset representing the value of the new tax deductions (calculated at 78 percent of the accrued asset removal obligation), was included as a reduction to the tax provision for the second quarter in the amount of NOK 2,380 million. Other income also included a gain of NOK 490 million on the sale of Hydro s share in Skandinaviska Raffinaderi AB, the Scanraff oil refinery and a gain of NOK 326 million resulting from the disposal of Hydro s ownership interest in Sundsfjord Kraft ANS.

Net financial income for 2003 was NOK 201 million, including a foreign exchange gain of NOK 1,035 million. During the course of 2003, the US dollar fell by four percent against the Norwegian krone, and weakened considerably against other currencies (roughly 17 percent against the Euro, and 25 percent against the Australian dollar). The US dollar movements have resulted in gains on Hydro s net US dollar denominated debt for the year as a whole. The weakness of the Norwegian krone has, however, resulted in losses on Hydro s net Euro denominated debt for 2003. Financial income for 2002 was NOK 1,935 million including a net foreign currency exchange gain of NOK 3,262 million.

The provision for current and deferred taxes for 2003 amounted to NOK 13,937 million, approximately 57 percent of pre-tax income. The tax provision has been strongly influenced by the effects of amendments to the Norwegian tax regulations relating to the future costs of removing oil and gas installations on the Norwegian continental shelf after production has ceased. In addition, the tax provision for the third quarter included a one time positive effect of NOK 139 million relating to the final conclusion of an outstanding tax ruling in Norway. Excluding these effects, tax expense amounted to 62 percent of pre-tax income for 2003.

The high tax percent in both 2003 and 2002 results because oil and gas activities in Norway, which account for a relatively large part of earnings, are charged a marginal tax rate of 78 percent.

Non-GAAP Measures of Financial Performance

Within this discussion, Hydro refers to certain non-GAAP financial measures which are an integral part of Hydro s steering model, Value Based Management, reflecting Hydro s focus on cash flow based indicators, before and after taxes. These non-GAAP financial measures are:

- EBITDA
- Gross Cash Flow
- Gross Investment
- Cash Return on Gross Investment (CROGI)

Hydro s management makes regular use of these cash flow-based indicators to measure performance in its operating segments, both in absolute terms and comparatively from period to period. Management views these measures as adding to the understanding, for management and for investors, of:

- The rate of return on investments over time, in each of its capital intensive businesses
- The operating results of its business segments
- Cash flow generation of its business segments

A reconciliation of Operating income to EBITDA for each of Hydro s operating segments is presented in the following table:

Operating income EBIT EBITDA 2003

Amounts in NOK million	**Operating income (loss)**	Non-cons. Investees	Interest Income	Selected financial income	Other income	**EBIT**	Depr. and amort.	**EBITDA**
Exploration and Production	**18,500**	29	32	4		**18,565**	9,059	**27,624**
Energy and Oil Marketing	**2,668**	81	35	(24)	816	**3,576**	650	**4,226**
Eliminations	**(25)**	(3)				**(28)**	4	**(24)**
Hydro Oil & Energy	**21,143**	107	67	(20)	816	**22,113**	9,713	**31,826**
Metals	**2,293**	379	3	53		**2,728**	1,570	**4,298**
Rolled Products	**132**	(14)	18	(5)		**131**	704	**835**
Extrusion and Automotive	**98**	68	22	(8)		**180**	1,252	**1,432**
Other and eliminations	**(67)**			1		**(66)**	(1)	**(67)**
Hydro Aluminium	**2,456**	433	43	41		**2,973**	3,525	**6,498**
Hydro Agri	**2,800**	610	192	(8)		**3,594**	1,154	**4,748**
Other activities	**(414)**	83	164	245	162	**240**	900	**1,140**
Corporate and eliminations	**(1,727)**	(4)	723	20	(2,190)1)	**(3,178)**	2,2191)	**(959)**
Total	**24,258**	1,229	1,189	278	(1,212)	**25,742**	17,511	**43,253**

1) Includes non-cash charge relating to an expected state grant pertaining to an asset removal obligation of NOK 2,207 million.

EBITDA and reconciliation to net income

Hydro defines EBITDA as Income/(loss) before tax, interest expense, depreciation, amortization and write-downs . EBITDA is intended to be an approximation of cash flow from operations before tax. EBITDA is a measure that includes in addition to Operating income , Interest income and other financial income , results from non-consolidated investees and gains and losses on sales of activities classified as Other income, net in the income statement. It excludes depreciation, write-downs and amortization, as well as amortization of excess values in non-consolidated investees. Hydro s definition of EBITDA may differ from that of other companies.

The EBITDA figures by core business area are presented in the table below, in addition to the reconciliation from EBITDA to income before taxes and minority interest.

Reconciliation to net income

Amounts in NOK million	**2003**	2002	2001
Hydro Oil & Energy	**31,826**	25,340	27,604
Hydro Aluminium	**6,498**	4,334	2,543
Hydro Agri	**4,748**	3,945	4,402
Other Activities	**1,140**	1,044	1,215
Corporate and Eliminations	**(959)**	995	1,993
Total EBITDA[1)]	**43,253**	35,658	37,757
Depreciation, depletion and amortization[2)]	**(15,093)**	(13,912)	(12,534)
Amortization of excess values in non-consolidated investees	**(211)**	(235)	(149)
Other income (expense) non-cash[3)]	**(2,207)**		
Interest expense	**(2,912)**	(3,189)	(3,721)
Capitalized interest	**715**	607	685
Net foreign exchange gain/(loss)	**1,035**	3,262	(416)
Other financial items	**(104)**	(163)	(157)
Income before tax and minority interest	**24,476**	22,028	21,465
Income tax expense	**(13,937)**	(13,278)	(13,750)
Minority interest	**148**	15	177
Income before cumulative effect of change in accounting principle	**10,687**	8,765	7,892
Cumulative effect of change in accounting principle	**281**		
Net income	**10,968**	8,765	7,892

1) EBITDA: Earnings Before Interest, Taxes, Depreciation and Amotization. EBITDA information by segment in each of the core business areas, as well as explanation of the financial performance of each segment, is

included in the presentation of the business areas.

2) Includes write-downs of property, plant, and equipment included in restructuring costs of NOK 261 million for 2001.

3) The amount relates to the reversal of an expected state grant pertaining to an asset removal obligation.

Another cash flow based indicator used by Hydro to measure its performance is cash return on gross investment (CROGI). CROGI is defined as gross cash flow after taxes, divided by average gross investment. Gross cash flow is defined as EBITDA less total tax expense. Gross investment is defined as total assets (exclusive of deferred tax assets) plus accumulated depreciation and amortization, less all short-term interest free liabilities except deferred taxes. CROGI has been Hydro s main financial return metric since 2000 and is used by management to measure financial performance at the operating segment level and the Group level.

In order to calculate Gross Cash Flow per operating segment, tax is also calculated for the operating segments. Tax is calculated by dividing each operating segment into the main tax regimes in which the segment operates, and applying the applicable statutory tax rates in those tax regimes to the taxable income/loss included in EBITDA. Taxable income/loss is typically Operating income , Interest income and other financial income and Other income/(expense), net . This taxable income for each operating segment is multiplied with the applicable average tax rate. For the sub-segment Exploration and Production an average tax rate of 60 percent is applied. An average tax rate of 50 percent is used for our Energy and Oil Marketing sub-segment. An average tax rate of 30 percent is being used for all other operating segments. This method represents an approximation to a tax expense for the operating segment. It does not, however, necessarily capture the effects of tax consolidation across the operating segments, which is permissible in certain countries where Hydro operates. Such effects are included at the Group level under the line Corporate and Eliminations in Hydro s segment disclosures. The allocated tax expense for the segments plus the tax expense reported under Corporate and Eliminations equals the total USGAAP tax expense for the Group as presented in the income statement. As Hydro is subject to significantly different tax regimes in its operating segments, e.g. Norwegian surtax on petroleum and power production, management believes financial performance must also be measured on an after tax basis, in order to achieve comparability between Hydro s operating segments.

In 2003, CROGI was 9.8 percent compared with 8.5 percent in 2002. CROGI for Hydro in total and each of the business areas is presented in the table below:

CROGI	**2003**	2002	2001
Hydro Oil & Energy	**13.0%**	12.1%	13.2%
Hydro Aluminium	**8.6%**	7.1%	5.7%
Hydro Agri	**11.7%**	9.4%	9.6%
Hydro	**9.8%**	8.5%	9.4%

EBITDA and Gross Cash Flow should not be construed as an alternative to operating income, income before taxes and net income as an indicator of Hydro s results of operations in accordance with generally accepted accounting principles. Nor are EBITDA and Gross Cash Flow an alternative to cash flow from operating activities in accordance with generally accepted accounting principles. Hydro s management makes regular use of measures calculated according to generally accepted accounting principles in addition to non-GAAP financial measures described above when measuring financial performance.

The following tables present a calculation of gross cash flow and gross investment for the Group as a whole and for each of the Business Areas:

Cash Return on Gross Investment Hydro

Amounts in NOK million	**Year ended 31 December 2003**	Year ended 31 December 2002	Year ended 31 December 2001
Operating income	**24,258**	19,841	21,083
Equity in net income of non-consolidated investees	**1,229**	33	566
Interest income and other financial income	**1,467**	1,418	2,847
Other income/expense, net	**(1,212)**	219	578
EBIT	**25,742**	21,511	25,074
Depreciation and amortization	**17,511**	14,147	12,683
EBITDA	**43,253**	35,658	37,757
Income tax expense	**(16,144)**	(13,278)	(13,750)
Gross Cash Flow	**27,109**	22,380	24,007

Amounts in NOK million	**31 December 2003**	31 December 2002	31 December 2001	31 December 2000
Current assets[1)]	**74,416**	64,179	78,217	80,113
Non-consolidated investees	**12,711**	11,499	9,687	7,211
Property, plant and equipment	**114,998**	112,342	95,277	95,025
Prepaid pension, investments and other non-current assets	**14,387**	15,081	11,636	10,983
Other current liabilities	**(42,890)**	(38,331)	(32,245)	(33,171)
Accumulated depreciation and amortization	**115,197**	101,907	97,930	92,385
Other	**(1,231)**	(1,281)	(1,663)	
Gross Investment	**287,588**	265,396	258,839	252,546

	31 December 2003	31 December 2002	31 December 2001
Cash Return on Gross Investment (CROGI)	**9.8%**	8.5%	9.4%

1) Excluding current deferred tax assets

Cash Return on Gross Investment Oil & Energy

Amounts in NOK million	**Year ended 31 December 2003**	Year ended 31 December 2002	Year ended 31 December 2001
Operating income	**21,143**	15,947	19,177
Equity in net income of non-consolidated investees	**107**	179	65
Interest income and other financial income	**47**	125	144
Other income/expense, net	**816**	77	179
EBIT	**22,113**	16,328	19,565
Depreciation and amortization	**9,713**	9,012	8,039
EBITDA	**31,826**	25,340	27,604
Income tax expense	**(12,911)**	(9,114)	(11,202)
Gross Cash Flow	**18,915**	16,226	16,402

Amounts in NOK million	**31 December 2003**	31 December 2002	31 December 2001	31 December 2000
Current assets[1)]	**15,564**	20,204	11,473	12,950
Non-consolidated investees	**2,406**	1,991	2,095	1,402
Property, plant and equipment	**74,460**	73,223	70,146	68,667
Prepaid pension, investments and other non-current assets	**1,294**	1,362	1,654	1,362
Other current liabilities	**(11,493)**	(16,589)	(8,732)	(9,133)
Accumulated depreciation and amortization	**68,186**	59,928	52,069	45,360

Gross Investment	**150,417**	140,119	128,705	120,608

	31 December **2003**	31 December 2002	31 December 2001
Cash Return on Gross Investment (CROGI)	**13.0%**	12.1%	13.2%

1) Excluding current deferred tax assets

Cash Return on Gross Investment Aluminium

Amounts in NOK million	**Year ended 31 December 2003**	Year ended 31 December 2002	Year ended 31 December 2001
Operating income	**2,456**	1,698	185
Equity in net income of non-consolidated investees	**433**	(219)	118
Interest income and other financial income	**84**	129	149
Other income/expense, net			(25)
EBIT	**2,973**	1,608	427
Depreciation and amortization	**3,525**	2,726	2,116
EBITDA	**6,498**	4,334	2,543
Income tax expense	**(737)**	(522)	(58)
Gross Cash Flow	**5,761**	3,812	2,485

Amounts in NOK million	**31 December 2003**	31 December 2002	31 December 2001	31 December 2000
Current assets[1)]	**22,925**	21,362	16,021	17,868
Non-consolidated investees	**5,787**	4,902	3,288	2,498
Property, plant and equipment	**29,504**	26,496	11,770	11,206
Prepaid pension, investments and other non-current assets	**3,880**	4,437	2,958	2,611
Other current liabilities	**(11,666)**	(10,080)	(8,610)	(8,351)
Accumulated depreciation and amortization	**21,158**	17,997	19,055	18,897
Other	**(1,231)**	(1,281)	(1,663)	
Gross Investment	**70,357**	63,833	42,819	44,729

	31 December	31 December	31 December

	2003	2002	2001
Cash Return on Gross Investment (CROGI)	**8.6%**	7.1%	5.7%

1) Excluding current deferred tax assets

Cash Return on Gross Investment Agri

Amounts in NOK million	**Year ended 31 December 2003**	Year ended 31 December 2002	Year ended 31 December 2001
Operating income	**2,800**	2,207	2,114
Equity in net income of non-consolidated investees	**610**	57	330
Interest income and other financial income	**184**	235	422
Other income/expense, net		166	(53)
EBIT	**3,594**	2,665	2,813
Depreciation and amortization	**1,154**	1,280	1,589
EBITDA	**4,748**	3,945	4,402
Income tax expense	**(895)**	(771)	(733)
Gross Cash Flow	**3,853**	3,174	3,669

Amounts in NOK million	**31 December 2003**	31 December 2002	31 December 2001	31 December 2000
Current assets[1)]	**13,672**	11,355	14,427	16,047
Non-consolidated investees	**2,498**	2,089	2,519	2,394
Property, plant and equipment	**7,189**	7,006	7,982	9,294
Prepaid pension, investments and other non-current assets	**960**	785	748	1,523
Other current liabilities	**(6,872)**	(6,223)	(6,385)	(6,923)
Accumulated depreciation and amortization	**17,602**	15,727	17,222	17,759
Gross Investment	**35,049**	30,739	36,513	40,094

	31 December **2003**	31 December 2002	31 December 2001
Cash Return on Gross Investment (CROGI)	**11.7%**	9.4%	9.6%

1) Excluding current deferred tax assets

Non-recurring or Infrequent Items

Hydro also identifies items of a non-recurring or infrequent nature in discussing operating results. These items reflect activities or events which management believes are not indicative of expected trends and outcomes arising from normal, recurring business operations. Generally such items arise as a result of very substantial initiatives including major turnarounds and other transforming events or material events and transactions which are not expected to occur often in the normal course of business. Non-recurring or infrequent items include but are not limited to :

- costs related to major improvement programs (which will vary from period to period and in certain periods may be insignificant, but which are identified nonetheless to enable investors to understand the total impact of such programs)
- material changes in the value of assets or liabilities related to infrequent events or major, unusual circumstances
- material gains or losses related to infrequent or non-recurring events or transactions

In general, Hydro excludes these items from financial measures calculated and presented in accordance with GAAP. This is not done with respect to other smaller, less comprehensive cost reduction programs, efficiency initiatives and business expansion activities which are viewed as normal, recurring activities and do not take away from investors understanding of the underlying business performance.

Hydro s Critical Accounting Policies

In December 2001, the SEC issued Financial Reporting Release No. 60, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, referred to as FR 60, suggesting that companies provide additional disclosure and commentary on those accounting policies considered most critical. FR 60 considers an accounting policy to be critical if it is important to a company s financial condition and results of operations and requires significant judgment and estimates on the part of management in its application. In December 2003, the SEC issued FR 72 which included additional guidance relating to critical accounting estimates. In this release, the SEC indicated that companies should consider providing enhanced discussion and analysis of critical accounting estimates that provides greater insight into the quality and variability of information regarding financial condition and operating performance.

Hydro s Consolidated Financial Statements and supplementary information were prepared in accordance with generally accepted accounting principles in the US (US GAAP). Note 1 in the Notes to the Consolidated Financial Statements describes Hydro s significant accounting policies. Inherent in many of the accounting policies is the need for management to make estimates and judgments in the determination of certain revenues, expenses, assets, and liabilities. The following accounting policies represent the more critical areas that involve a higher degree of judgment and complexity which, in turn, could materially impact Hydro s financial statements if various assumptions were changed significantly. Hydro s senior management has discussed estimates underlying certain of its critical accounting policies with its independent auditors.

Hydro believes that the following represents its critical accounting policies as contemplated by FR 60.

Oil and Gas Exploration Costs

Hydro uses the successful efforts method of accounting for oil and gas exploration and development costs. All expenditures related to exploration, with the exception of the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized on the balance sheet pending determination of whether commercially producible oil and gas reserves have been discovered. If the determination is made that a well did not encounter potentially economic oil and gas quantities, the well costs are charged to expense.

Almost all of our wells capitalized on the balance sheet at December 31, 2003, 2002 and 2001 are in offshore areas where a major capital expenditure (e.g., offshore installation) would be required before production could begin. In such areas, the economic viability might depend on the completion of additional exploratory drilling and the discovery of sufficient commercially producible reserves. Once the additional exploration drilling demonstrates that sufficient quantities of reserves have been discovered, continued capitalization is dependent on project reviews, which take place periodically and no less frequently than every quarter, to ensure that satisfactory progress toward ultimate development of the reserves is being achieved.

For complicated offshore exploratory discoveries, it is not unusual to have exploratory well costs remain suspended on the balance sheet for several years while additional appraisal work on the potential oil and gas field is performed and regulatory approvals for development are sought. In all the areas in which we operate, plans for development are subject to governmental approval. The wells are transferred to development when the Plan for Development and Operation (PDO) has been submitted to the Ministry of Petroleum and Energy (Norway) or matured to a level corresponding to a PDO submittal (International).

Costs related to acquisition of exploration rights are allocated to the relevant geographic areas and are charged to operating expense if no proved reserves are determined to exist. If proved reserves are determined to exist, the acquisition costs are transferred to development cost, and subsequently amortized to become part of the cost of the oil and gas produced.

A determination that proved reserves do not exist can result in a reduction to long-term assets and an increase in operating costs. Each block or area is assessed separately. The amount of the impact depends on the level of current drilling activity and the amount of exploration costs currently capitalized. During 2003, exploration activity (expenditures) totaled NOK 1,609 million, of which NOK 120 million was capitalized during the year. Including capitalized exploration costs and acquisition costs from prior periods, NOK 1,577 million was expensed during the year. At the end of 2003, NOK 1,023 million of such costs were capitalized pending the evaluation of drilling results and planned development, of which NOK 33 million related to acquisition costs.

In connection with the review of our 2002 Form 20-F, the staff of the SEC s Division of Corporation Finance has raised questions about our practice of deferring costs (i.e., continuing to carry such costs as an asset on our balance sheet) related to certain exploratory wells. The wells in question have all demonstrated commercial quantities and the drilling of wells on the properties in question has been completed. Work related to development concept optimization and PDO submission /authority approval is ongoing. Capitalized exploration costs net of property acquisition costs amounted to NOK 990 million as of December 31, 2003. The capitalized exploration costs of the wells in question represent approximately one-third of the net capitalized exploration costs at the end of 2003. The vast majority of these wells are located on the Norwegian Continental Shelf, where the combined tax rate is 78% of income before taxes. Therefore, in the event that it is determined that some or all of these costs should be expensed, the accumulated effect on net income would be reduced by the tax effect.

Proved Oil and Gas Reserves

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves are related to developed fields (proved developed reserves), and to undeveloped fields (proved undeveloped reserves). The estimation of proved reserves is based on technical evaluations using all available reservoir, well and production data. Proved reserves does not include volumes after license expiry or volumes that are not commercially producible with known technology and prices at year end.

Reserves are revised upwards or downwards as oil and gas are produced and additional data become available. Revisions can result from evaluation of already available geologic, reservoir or production data, or from new geologic or reservoir data obtained from wells. Revisions can also include changes resulting from performance of improved recovery projects, production facility capacity, significant changes in development strategy, oil and gas prices or changing regulatory environment.

Proved developed reserves are the basis for calculating unit-of-production depreciation. Future changes in proved oil and gas reserves can materially impact unit-of-production rates for depreciation, depletion, and amortization. Downward revisions in reserve estimates can result in higher depreciation and depletion expense in future periods. Conversely, upward revisions in reserve estimates can result in lower future depreciation, depletion and amortization. Depreciation, depletion and amortization related to oil and gas producing activities in 2003, 2002 and 2001 were NOK 9,114 million, NOK 8,553 million and NOK 7,423 million respectively.

Commodity Instruments and Risk Management Activities

Hydro s revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing commodity prices for oil, aluminium and the US dollar exchange rate. The historical volatility in these commodity prices materially affects Hydro s financial condition, liquidity, ability to obtain financing, and operating results. Depressed prices can have a negative impact on Hydro s financial results. The majority of Hydro s oil and aluminium production is sold at market prices. To mitigate unwanted price exposure and to protect against undesirable price developments, Hydro utilizes physical and financial commodity instruments on a limited basis. Entering into such positions requires management to make judgments about market conditions and future price expectations. Certain commodity instruments are deemed to be derivatives under US GAAP and required to be recognized at fair value, with changes in the fair value impacting earnings. When market prices are not directly observable through market quotes, the estimated fair value must be calculated using valuation models, relying on internal assumptions as well as observable market information. Such assumptions includes forward curves, yield curves and interest rates. The use of models and assumptions are in accordance with prevailing guidance from the FASB and valuations are based on the Company s best estimates. However, changes in valuations will likely occur and such changes may have a material impact on the estimated fair value of derivative contracts, in particular long-term contracts, resulting in corresponding gains and losses affecting future periods income statements. It is important to note that use of such instruments may preclude or limit Hydro s ability to realize the full benefit of a market improvement. To further understand Hydro s sensitivity to these factors please refer above to the Indicative income statement sensitivities table on page 107 .

Asset Retirement Obligations

Hydro has adopted as of January 1, 2003 SFAS 143, Accounting for Asset Retirement Obligations. Among other things, SFAS 143 requires significant changes in the accounting treatment for asset retirement obligations such as abandonment of oil and gas production platforms, facilities and pipelines. Specifically, the fair value of a liability for an asset retirement obligation is required to be recorded when incurred. Furthermore, the liability is to be accreted for the change in its present value each reporting period.

Hydro s asset retirement obligations consist mainly of accruals for removal and decommissioning of oil and gas installations on the Norwegian Continental Shelf. Norwegian regulations and the OSPAR convention (convention for the protection of the marine environment of the north-east Atlantic) regulate which installations must be disposed of and which can be abandoned. The OSPAR convention has imposed a general ban on sea disposal of offshore installations and requires removal and recycling unless exceptions are made which allow abandonment of specific installations.

The OSPAR convention does not cover pipelines and cables. Report No. 47 (1999-2000) to the Storting (Norwegian Parliament) on the disposal of pipelines and cables that have ceased to be used includes general guidelines permitting such facilities to be left in place if they do not result in any inconvenience or safety hazards.

A termination and removal plan for each field must be approved by the Norwegian authorities. The asset retirement obligation is estimated as the present value of the future expected decommissioning and removal costs based on an expected retirement concept and timing. The timing of retirement activities is normally assumed to be the end of production. Retirement activities relating to fields where Hydro has an ownership interest are expected to begin relatively far into the future. There is substantial uncertainty in the scope and timing of future termination and removal activities. Changes to technology, Norwegian regulations and other factors may affect the timing and scope of retirement activities. Such changes may substantially alter the book value of property, plant and equipment, asset retirement obligations and future operating costs.

Classification of mineral interests in oil and gas properties

A discussion is currently ongoing within the oil industry regarding the classification of mineral interests in oil and gas properties. Hydro has historically reported and currently reports such interests as part of Property, Plant and Equipment. The industry s current practice as to the proper classification of acquisition of contractual mineral interests under SFAS 141 Business Combinations and SFAS 142 Goodwill and Intangible Assets has been questioned. The Financial Accounting Standards Board (FASB) has issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1, addressing certain aspects of this discussion. In addition, Emerging Issues Task Force (EITF) 04-2 addresses a related issue, whether mineral rights are tangible or intangible assets, concluding that such assets are tangible assets. Furthermore, mineral rights are required to be separately disclosed in reporting periods beginning after 31 March, 2004. However, this statement applies only to mining entities, while oil- and gas-producing entities within the scope of SFAS 19 are excluded. The EITF has included the topic for oil and gas-producing entities on its agenda as Issue No. 03-S, stating that consideration of this issue will be consistent with the approach taken with regard to mineral rights related to mining enterprises. Thus further authoritative guidance on the issue is expected.

The majority of Hydro s oil and gas producing fields and fields under development are offshore fields in various parts of the world and at various water depths. Development of these fields involves installations and production facilities tailored to each development. Hydro has not considered it beneficial to report acquired mineral interests in oil and gas properties and assets related to the development of these properties (e.g., offshore production platforms, wells and equipment) separately.

Hydro has made one significant acquisition of mineral interests in oil and gas properties subsequent to the implementation of SFAS 141 and SFAS 142 in 2001: the acquisition in May 2002 of increased interests in certain oil and gas producing fields and fields under development on the Norwegian Continental Shelf (NCS) from the Norwegian State. Consistent with Hydro s historical practice, the acquired interests, including offshore production platforms, wells and equipment, were recorded as Property, Plant and Equipment in the consolidated balance sheet, of which mineral interests in oil and gas properties were NOK 1.5 billion, all of which was assigned to proved reserves in producing fields and fields in development phase. Should new accounting guidance require hydrocarbon reserves obtained in acquisitions of oil and gas properties to be reported separately, either as tangible or intangible assets, the maximum amount Hydro would reclassify in accordance with such guidance is approximately NOK 1.3 billion as of December 31, 2003, and NOK 1.4 billion as of December 31, 2002. The determination of these amounts is based on Hydro s current understanding of this issue. A reclassification would not be expected to change Hydro's result of operations or cash flows. Hydro will continue to classify these assets as part of Property, Plant and Equipment until authoritative guidance is provided.

Impairment of Long-Lived Assets

Hydro adopted as of January 1, 2002 SFAS 144, Accounting for Impairment or Disposal of Long-Lived Assets. Under SFAS 144, management is required to assess the conditions that could cause an asset to become impaired and require a write-down upon determination of impairment for long-lived assets held by the Company. These conditions include whether a significant decrease in the fair value of the asset(s) has occurred, changes in the Company s business plan for the asset(s) have been made, or whether a significant adverse change in the local business and legal climate has arisen. The amount of such an impairment charge is based on the estimated fair value of the asset compared to its carrying value. Fair value measurements include assumptions made regarding future cash flows associated with the asset under evaluation.

Impairment charges result in a decrease to Property, Plant and Equipment on the balance sheet and an increase in operating costs.

Contingencies and Environmental Liabilities

Contingencies and environmental liabilities are recorded when such items are asserted, or are probable of assertion, and the amount of potential loss can be reasonably estimated. Evaluation of contingencies requires management to make assumptions about the probability that contingencies will be realized and the amount or range of amounts that may ultimately be incurred. Environmental liabilities require interpretation of scientific and legal data, in addition to assumptions about probability and future costs. Changes in these assumptions can affect the timing and amounts of recorded liabilities and costs.

Business Combinations

In accounting for the acquisition of businesses, Hydro is required to determine the fair value of assets, liabilities, and intangible assets at the time of acquisition. Purchase accounting is subject to a number of assumptions including useful lives of assets, discount rates in different environments, replacement costs and timing of certain future cash flows.

Hydro s most recent significant acquisition was the purchase of VAW for a purchase price of EUR 1,911 million (NOK 14.9 billion). A specification of the allocation of this purchase price to assets and liabilities acquired can be found in Note 2 in Notes to the Consolidated Financial Statements.

Goodwill and Intangible Assets

Under SFAS 142, Goodwill and Other Intangible Assets, implemented in 2002, goodwill and certain intangible assets are no longer systematically amortized, but reviewed at least annually for impairment.

The largest portion of goodwill was recorded in the North America sector of the Extrusion and Automotive sub-segment. Management assessed the fair value of the sector s goodwill in relation to the carrying value of the sector s net assets. Assumptions related to certain cash flow forecasts and the discount rate were made reflecting the sector s industry. Total goodwill evaluated for impairment during 2003 was approximately NOK 1,100 million. Intangible assets determined to have indefinite useful lives are not amortized until a finite life can be estimated. Such assessment requires management to look at the legal, regulatory, competitive, and contractual factors to determine whether the useful life of the asset acquired is considered to be indefinite. Currently, Hydro has intangible assets with a carrying value of NOK 5 million deemed to have indefinite life. Goodwill and intangible assets are included in prepaid pension, investments, and other non-current assets.

Income Taxes

Hydro calculates deferred income tax expense based on the difference between the tax assets carrying value for financial reporting purposes and their respective tax basis that are considered temporary in nature. This computation requires management s interpretation of complex tax laws and regulations in many tax jurisdictions where Hydro operates. Valuation of deferred tax assets is dependent on management s assessment of future recoverability of the deferred benefit. Management s judgment may change and such change may affect the results for each reporting period.

Employee Retirement Plans

Hydro s employee retirement plans consist primarily of defined benefit pension plans. As of December 31, 2003, the projected benefit obligation (PBO) associated with Hydro s defined benefit plans was NOK 29.2 billion. The fair value of pension plan assets was NOK 18.7 billion, resulting in a net unfunded obligation relating to the plans of NOK 10.5 billion. In addition, termination benefit obligations and other pension obligations amounted to NOK 1.5 billion, resulting in a total net unfunded pension obligation of NOK 12 billion. Hydro's net pension cost for 2003 amounted to NOK 2.5 billion. Cash outflows from operating activities in 2003 regarding pensions amounted to NOK 2 billion. The discount rate used for determining pension obligations and pension cost is based on the yield from a portfolio of long-term corporate bonds having one of the two highest ratings given by a recognized rating agency. Hydro provides defined benefit plans in several countries and in various economic environments that will affect the actual discount rate applied. Almost two-thirds of Hydro's projected benefit obligation relates to Norway. The discount rate applied for Norwegian plans as of December 31, 2003 is six percent. Measurement of pension cost and obligations under the plans requires a number of assumptions and estimates to be made by management. These include future salary levels, inflation, discount rates, years of future service, and rate of return on plan assets. Changes in these assumptions can influence the funded status of the plan as well as the net periodic pension expense. The PBO is sensitive to changes in assumed discount rates and assumed compensation rates. Based on indicative sensitivities, a one percentage point reduction or increase in the discount rate will increase or decrease the PBO in the range of 15 to 20 percent. A one percentage point reduction or increase in compensation rates for all plan member categories will decrease or increase the PBO in the range of 15 to 20 percent. It should be noted that changes in the aforementioned parameters and changes in the PBO, will affect net periodic pension cost in subsequent periods, both the service cost and interest cost components, in addition to amortization of unrecognized net gains or losses, if any.

Business Segment Information

Prior to the demerger of Agri, Hydro's operating segments consisted of the three core business areas Oil and Energy, Aluminium and Agri. Each business area is divided into sub-segments representing different parts of the value chain as follows:

Oil and Energy:	Exploration and Production
	Energy and Oil Marketing
Aluminium:	Metals (Primary Metals and Metal Products)
	Rolled Products
	Extrusion and Automotive (including the North America sector)
Agri:	Agri (Fertilizer and Industrial Gases and Chemicals)

In addition, Hydro is in the petrochemicals business and is engaged in other activities. A discussion of the operating results for each of the sub-segments within Hydro s core business areas, as well as for Other Activities, follows.

Hydro Oil & Energy

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**59,959**	55,845	52,180
Operating Income	**21,143**	15,947	19,177
EBITDA	**31,826**	25,340	27,604
Gross Investment	**150,417**	140,119	128,705
CROGI	**13.0%**	12.1%	13.2%
Number of employees	**3,465**	4,039	3,891

Hydro Oil & Energy consists of the sub segments Exploration and Production and Energy and Oil Marketing .

Summary of key developments in 2003

Hydro Oil & Energy s operating income in 2003 was NOK 21,143 million, an increase of 33 percent compared to 2002. The most significant developments that influenced Hydro Oil and Energy s operating income in 2003 were as follows:

Oil and gas production increased by 10 percent to an average of 530,000 boe per day (boed). The increase came both from Norwegian and international fields. During 2003 a number of new fields commenced production, Grane being the most important.

Oil and gas prices were high throughout the year. Oil prices increased in 2003 reaching an average realized oil price of US dollar 28.7, up 16 percent from US dollar 24.7 in 2002. However the depreciation of the US dollar against NOK offset much of the effect of the price increase. Realized oil prices measured in NOK increased by approximately 4 percent compared to the previous year. Realized gas prices increased by approximately 7 percent.

Exploration costs in 2003 were NOK 1,577 million, a reduction of 56 percent compared to the previous year. The decline reflects a 32 percent reduction in the level of exploration activity for 2003 compared to the previous year in addition to a lower level of previously capitalized exploration and acquisition cost expensed in the period. There were 13 exploration wells drilled and completed in 2003 resulting in three discoveries. In addition, two discoveries were announced in Angola during the first quarter of 2003 based on exploration activity in 2002.

Hydro s proved oil and gas reserves were 2,288 million barrels of oil equivalents (mboe) at the end of 2003, compared to 2,225 mboe at the end of 2002. Hydro s reserve replacement ratio for 2003 was 133 percent, including reserves of 1.5 mboe relating to sold interests in the Brage and Njord fields. The reserve replacement ratio was 134 percent excluding purchases and sales of license interests. The increase in the reserves resulted from the inclusion of new fields in Norway, in particular Ormen Lange (SEC reserves; 234 mboe) and Vestflanken, as well as revisions of reserves relating to producing fields. Reserve life (defined as the number of years of production from proved reserves at the present production level) was 12 years at the end of 2003; comprised of 7 years for oil and 27 years for gas.

Hydro continued activities to optimize its license portfolio during the year. In 2003, approval was received from the Norwegian authorities for the sale of interests in the Brage and Njord fields. In addition, Hydro entered into an agreement for the sale of its interest in the Gjøa field. The sale was approved by the authorities in January 2004 and resulted in a tax-free gain of NOK 280 million that was reflected in the results in the first quarter of 2004. In January 2004, the Company signed an agreement to sell its 10 percent share in the Snøhvit field to Statoil. The transaction is expected to result in an after tax gain of roughly NOK 100 million. At the same time an agreement was reached for the purchase of a two percent share in the Kristin field increasing Hydro s interest in the field to 14 percent of the field, improving its position in the Norwegian Sea Area on the NCS. Both agreements reflect Hydro s strategy to optimize its oil and gas portfolio.

During 2003, Hydro sold its interest in the company that owns the Scanraff refinery in Sweden (Scandinaviske Raffinaderi AB). The transaction resulted in a gain of NOK 490 million that is reflected in the results of 2003.

Operating cost per barrel for Hydro s oil and gas production was NOK 84 per boe in 2003 compared to NOK 100 per boe in 2002. The main reason for the reduction was lower exploration costs compared to 2002. In addition, increased production resulted in lower costs per barrel due to greater economies of scale. During 2003 Hydro rationalized parts of its administrative and exploration organizations including manning reductions of approximately 60 people and a substantial reduction in the use of external consultants. This was in addition to the 535 employees that were transferred to Statoil as of January 1, 2003 in connection with the transfer of operatorship on the Tampen fields. Operating costs excluding exploration were NOK 76 per boe in 2003 compared to NOK 79 per boe in 2002, well below the announced target of NOK 82 per boe.

Power production in 2003 was 27 percent lower than 2002 and lower than normal from hydro powered production plants. Prices in the Nordic electric power market were NOK 0.29 per kWh, compared to NOK 0.20 in the prior year.

The change in 2003 operating income compared to the prior year and the most important items affecting the change are included in the table below.

Amounts in NOK million	**2003**
Operating income 2003	21,143
Operating income 2002	15,947
Change in Operating Income	5,196
Prices and currency for E&P	
- oil	4,110
- gas	485
- currency	(2,835)
- put options	110
	1,870
Margin	205
Volume	2,515
Fixed costs	10
Depreciation	(640)
Production costs	(440)
Exploration costs	1,980
Other	(304)
Total change in Operating Income	5,196

The main reasons underlying the material variances are described in the summary above.

Exploration and Production

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**37,904**	32,970	32,426
Operating Income	**18,500**	13,137	16,910
EBITDA	**27,624**	21,593	24,312
Gross Investment	**124,655**	115,938	106,382
CROGI	**13.7%**	12.2%	13.7%
Number of employees	**2,800**	3,372	3,213

Exploration and Production (E&P) includes Hydro s oil and gas exploration activities, field development activities and oil and gas production activities. Hydro currently has production of oil and gas in Norway, Canada, Angola, Libya and Russia. Effective January 1, 2003, Hydro s gas transportation assets were transferred from the Exploration and Production sub-segment to the Energy and Oil Marketing sub-segment. All prior periods have been reclassified for comparative purposes.

Market Conditions

Oil prices increased in 2003 reaching an average realized oil price of US dollar 28.7, up 16 percent from US dollar 24.7 in 2002. The higher oil prices were mainly due to political turmoil in Venezuela affecting the oil industry in particular; the onset of war in Iraq; a very cold winter in the US; high US natural gas prices and the beginning of a global economic recovery creating increased demand for crude oil. These circumstances were in addition to OPEC actions to maintain high oil prices levels. However the depreciation of the US dollar against NOK offset much of the effect of the price increase. Expressed in Norwegian kroner the oil price went up from NOK 194 in 2002 to NOK 203 in 2003, an increase of 4 percent. The average realized gas price in 2003 was NOK 1.03 per standard cubic meter, up 7 percent from NOK 0.95 per standard cubic meter in 2002. The increase reflected higher prices of oil products (gas prices in long term contracts are to a large extent linked to the price of oil products with a lag of approximately six months).

Revenues

Operating revenues for E&P in 2003 were NOK 37,904 million, an increase of 15 percent from the previous year. In addition to the higher price levels experienced for oil and gas, the increase reflected substantial growth in total production volumes. During 2003, average production increased from 480,000 boed in 2002 to 530,000 boed. The increase of approximately 10 percent was well above the forecast for the year and in line with a targeted 8 percent compound annual growth rate for the 2001-2007 period. Oil production increased by 7 percent and accounted for 74 percent of the total production compared to 77 percent in 2002. Gas production increased to a total of 7.8 billion standard cubic meters, an increase of 22 percent compared to 6.4 billion standard cubic meters in 2002. Oil and gas production reached a record level in the fourth quarter with an average production of 596,000 boed.

Hydro experienced production growth both from Norwegian and international fields in 2003. New fields coming on stream in Norway included the Grane, Mikkel, Fram and the satellite Vigdis extension. In addition, Jasmim in Angola and the Murzuq A field in Libya started production in the fourth quarter of 2003. Production also increased from fields coming on stream in recent years including Tune, Snorre B, Åsgard, Oseberg Sør, Girassol and Terra Nova.The increased interests in Hydro operated Oseberg, Tune and Grane fields pur-

chased from the Norwegian State on May 10, 2002 also contributed to the growth with a full year effect in 2003. International production outside the Norwegian Continental Shelf (NCS) accounted for 11 percent of the total production, up from 10 percent in 2002. Planned maintenance stops caused a production loss (or delayed production) of 12,000 boed compared to 9,000 boed in 2002.

Because the Energy and Oil Marketing sub-segment purchases and sells Hydro s Norwegian equity production of oil, about 68 percent of Exploration and Production s revenues in 2003 resulted from internal sales. Equity production of gas and international oil production are sold by Energy and Oil Marketing on behalf of Exploration and Production and account for the majority of the external revenues.

Operating Costs

Operating costs for E&P were NOK 19,404 million in 2003, a decrease of 2 percent compared to the previous year.

Hydro s average production cost, defined as the cost of operating fields, including CO_2 emission tax, insurance, gas purchased for injection and lease costs for production installations (but excluding transportation and processing tariffs, operating cost of transportation systems and depreciation), was NOK 21 per boe in 2003, compared to NOK 23 per boe in 2002. The main reasons underlying the cost reduction were increased production, better productivity and the implementation of extensive cost control measures within Hydro s portfolio of producing fields.

Depreciation, including accruals for abandonment and well closure costs and write-downs (but excluding depreciation on transportation systems), averaged NOK 46 per boe, the same level as in 2002. However, total depreciation costs increased in 2003 as a result of higher production levels. Total exploration costs including appraisal costs of discoveries amounted to NOK 1,577 million in 2003 compared to NOK 3,558 million in 2002. The decline compared to 2002 resulted from lower exploration activity and a substantially lower level of previously capitalized exploration and acquisition cost expensed during the period. Cost relating to exploration activity in 2003 was NOK 1,609 million, compared to NOK 2,376 million in the previous year. Seventy-three percent of the exploration activity was dedicated to areas outside the NCS, mainly in Angola, Canada, Iran and the Gulf of Mexico. Out of a total of 13 exploration wells drilled and completed during 2003, one discovery was made in the Gulf of Mexico and two discoveries were made in Norway. In addition, two wells were in the process of being drilled at year-end. Cost of NOK 1,489 million relating to 2003 exploration activities was expensed due to unsuccessful efforts in Angola, Canada and Norway. NOK 88 million relating to costs capitalized in previous years was also expensed.

Operating Income

Operating income in 2003 was NOK 18,500 million, a 41 percent increase from the previous year. As discussed above, the main reasons underlying the increase were higher production volumes, lower exploration costs and higher oil and gas prices.

EBITDA

EBITDA in 2003 was NOK 27,624 million, an increase of NOK 6,031 million compared to 2002.

Outlook

Hydro will continue to focus its exploration and production strategy for the coming years on growing Hydro s exploration and production activities, balancing the portfolio and continuing to focus on cost improvements to improve profitability.

Following a review of the extensive drilling program completed during 2001-2003, Hydro plans to take measures to reduce the risk profile of its exploration activities. Hydro will evaluate purchasing discovered petroleum resources in areas where Hydro s particular strengths in drilling, reservoir management and field development can add greater value. For 2004 Hydro will scale back exploration activity to a level of around NOK 1 billion, and anticipates an annual level of NOK 1.5 billion for 2005.

Hydro s objective is to maintain its position as an efficient operator on the NCS. Hydro has targeted production cost of NOK 24 per boe for 2004. The increase of about NOK 3 per boe compared to 2003 to a large extent results from the cost of purchasing injection gas to increase the oil production on the new Grane field.

Hydro expects its oil and gas production to increase by approximately 8 percent as an annual average during the period 2001-2007 based on its current portfolio of fields in production, fields under development or fields considered for development. The production target for 2004 is an average of 560,000 boed of which approximately 90 percent comes from fields with currently booked proved reserves. Increased production from the Grane field is expected to contribute strongly to the growth in 2004.

A main focus for Hydro in 2004 is the development of the Ormen Lange gas field on the NCS. This is the largest undeveloped gas field on the NCS, at a water depth of 850 to 1,100 meters. The Plan for Development and Operation (PDO) was submitted to the authorities for approval on 4 December 2003 together with the plan for installation and operation of the Langeled gas export pipeline from the field to the United Kingdom. Approval of the PDO occurred in April 2004. Hydro is the operator during the development phase of the field. Production is scheduled to begin in 2007. Total investments including the gas export pipeline is estimated to be NOK 66 billion excluding estimated inflation over the life of the project. Hydro holds an ownership interest in the field of 18.0728 percent.

Crude oil prices have been high for the last three years and current forward market prices indicate that prices will remain high in 2004. It is expected that OPEC will manage crude production to maintain price levels within their USD 22-28 price band target for their basket of crude oil types for 2004. The growth in demand resulting from global GDP growth and increased demand for oil in new production and transportation systems (refineries, pipelines, terminals etc.) is expected to be balanced by growth in non-OPEC production, increased oil production from Iraq and production cuts from the remaining OPEC countries if needed.

Energy and Oil Marketing

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**49,370**	45,915	45,824
Operating Income	**2,668**	2,784	2,267
EBITDA	**4,226**	3,721	3,292
Gross Investment	**25,734**	24,128	22,366
CROGI	**9.8%**	11.2%	10.6%
Number of employees	**665**	667	678

Energy and Oil Marketing includes Hydro s commercial operations in the oil, natural gas and power sectors, the gas transportation operations and the operation of Hydro s power stations in Norway. Energy and Oil Marketing markets and sells refined petroleum products (gasoline, diesel and heating oil) to customers in Scandinavia and the Baltic countries. Hydro owns 100 percent of the operating unit in Sweden and 50 percent of Hydro Texaco, an oil marketing company with retail outlets in Norway, Denmark and the Baltic countries. Energy and Oil Marketing is also responsible for developing Hydro s hydrogen and renewable energy business activities such as wind power. In 2003, Hydro sold its interest in the company that owns the Scanraff refinery in Sweden (Scandinaviske Raffinaderi AB). As a result, Hydro no longer holds an interest in the refining business. Results from the operation of Scanraff are included until 17 December 2003.

Except for the operation of Hydro s own power stations, gas infrastructure activities and development activities, Energy and Oil Marketing s business mainly consists of margin-based sales and trading activities. As a result, operating revenues and costs in any given year are largely a function of volume traded and the level of prevailing market prices for crude oil, natural gas and electricity.

Market Conditions

As described under the caption Market Conditions for the Exploration and Production sub-segment, the price level for oil, oil products and gas was higher during 2003 and somewhat higher than in 2002.

Nordic electricity prices were high during 2003 as a result of unusually low precipitation during autumn 2002 resulting in low reservoir levels. The situation improved in Norway and Sweden during 2003, but reservoir levels were around 20 percent lower than normal at the end of the year. Average spot prices for 2003 were NOK 0.29 per kWh, compared to NOK 0.20 per kWh in the prior year.

Operating Revenues

Energy and Oil Marketing s operating revenues for 2003 were NOK 49,370 million, up NOK 3,455 million or 8 percent from the prior year.

Power production in 2003 was 7.5 TWh compared with 10.3 TWh in 2002, a reduction of 27 percent and below normal production from the hydroelectric power plants. The decrease in production from Hydro s hydroelectric power plants was expected due to low reservoir levels at the beginning of the year.

In 2003, internal sales to other business areas within Hydro amounted to NOK 5,062 million, including internal sales to Hydro Agri and Hydro Aluminium Metals sub-segment of NOK 1,596 million and NOK 1,776 million, respectively. Internal sales in 2002 were NOK 3,986 million.

Operating costs

Energy and Oil Marketing s operating costs of NOK 46,702 million in 2003 were 8 percent higher than the prior year. As described above, Energy and Oil Marketing s operating costs are mainly comprised of purchases of crude oil, natural gas and electricity. Operating costs also include process costs relating to the operations of power stations, gas infrastructure and other fixed costs. There were no substantial changes in these costs in 2003 compared to the previous year.

Operating income

Energy and Oil Marketing s operating income in 2003 was NOK 2,668 million, a decrease of 4 percent compared to the prior year. The main change in 2003 was a decrease in operating income from power sourcing and marketing activities which to a large extent was offset by an increase in the operating income from the gas activities.

Operating income from power sourcing and marketing activities was NOK 664 million in 2003, down NOK 521 million or 44 percent from the prior year. The decrease in operating income resulted primarily from lower production, which was partly offset by higher average spot prices. In addition, unrealized gains relating to power purchase contracts increased the results for 2002 by NOK 220 million. Energy and Oil Marketing secures electricity in the market for Hydro s own consumption, for delivery to external parties and to reduce the risk of price fluctuations on its electricity portfolio. In 2002 Hydro purchased electricity contracts in the derivative market for deliveries in 2003 to compensate for the low reservoir levels and expected shortfalls in production. Spot and forward electricity prices fell in the early part of 2003 compared to an exceptionally high level at the end of 2002. As a result, a portion of the net unrealized gains relating to these contracts that were included in the results of 2002 were reversed in 2003 as expected.

Operating income from oil trading and refining activities was NOK 406 million in 2003, an increase of 5 percent from the prior year. These activities include crude oil trading, gas liquids trading, refining activities and shipping. Strong refining margins and good trading results in the markets for gas liquids and crude oil were offset by inventory losses related to refining activity. Average refining margins for 2003 were US dollar 4.4 per barrel, compared to US dollar 2.2 per barrel in 2002. Operating income in 2003 included an inventory loss of NOK 82 million compared to an inventory gain of NOK 64 million in 2002.

Operating income from gas activities was NOK 1,795 million in 2003, up NOK 540 million from the prior year (43 percent). Around NOK 190 million of the improved operating income came from gas sourcing and marketing activities, while the remaining improvement related to gas infrastructure activities. The improved results from gas infrastructure activities were mainly due to higher tariff revenues, and lower depreciation charges resulting from the extension of license periods for a number of gas pipelines following the establishment of Gassled in January 2003.

Oil Marketing incurred an operating loss of NOK 16 million compared to operating income of NOK 68 million in 2002. The decline reflects lower margins and higher inventory losses.

EBITDA

EBITDA for 2003 was NOK 4,226 million, an increase of 14 percent compared to the prior year. Hydro s share of net income from Hydro Texaco included in EBITDA was NOK 117 million in 2003, the same level as in the prior year.

In 2003, Hydro sold its interest in Sundfjord Kraft ANS for 20.2 percent of the shares of SKS Produksjon AS resulting in a gain of NOK 326 million reflected in the results.

The sale of Hydro s 25 percent ownership interest in the Scanraff oil refinery in Sweden resulted in a gain of NOK 490 million reflected in the results for the year.

Outlook

Hydro power reservoir levels were below average at year-end 2003 for Hydro-owned power stations and for the Nordic market area in general. As a result, the Company s hydro power generation in 2004 is expected to be approximately 12 percent below the normal levels. The present reservoir deficit in the Nordic market area results in an expected price level above historic average. However, this estimate is uncertain and depends on precipitation levels during the next few months. Spot and forward prices for 2004 are below the 2003 levels at present, however, the tighter Nordic power balance has increased dependence on electricity imports and energy from other sources. Lack of new capacity to cover expected annual demand growth of more than 1 percent is expected to result in a tighter capacity balance in the coming years. Prices in the Nordic Region will be influenced by electricity prices within the European continental market that are high mainly due to record high coal prices. Prices could increase further in 2004 due to restrictions on greenhouse gas emissions in the European Union.

The European continental gas market continues to be dominated by long-term contracts indexed to oil products. The ongoing liberalization process of the European gas market is expected to lead to a more liquid and short-term gas market on the continent similar to what has existed in the UK for some time. New gas trading hubs are emerging, in particular at Zeebrügge in Belgium, in the Netherlands and at Emden/Bunde at the German/Dutch border. Hydro expects to be able to exploit business opportunities resulting from these developments. In 2003, Hydro strengthened its position in the continental gas market through the acquisition of Duke Energy s marketing activities in the Netherlands (Duke Energy Europe Northwest B.V). Hydro also established a joint venture, HydroWingas Ltd, with German gas supplier Wingas GmbH. HydroWingas will market gas in the UK, focusing on wholesalers and large end-users. In 2003, Hydro also signed an agreement with A.P. Møller-Maersk A/S, a Danish company, for the purchase of 0.6 billion cubic meters of gas per year during the period 2005 to 2009 for delivery in the Netherlands. Hydro believes that the long-term fundamental conditions underlying natural gas demand in Europe are strong in part because natural gas continues to be the preferred choice for new supplies due to environmental benefits, competitive pricing and convenience of use. Hydro will continue to focus on profitable growth of its gas portfolio both upstream and downstream to capture the opportunities created by a more flexible and liquid European gas market.

Following the Scanraff sale in December 2003, Hydro no longer holds an interest in the refining business. Operating income relating to this activity was approximately NOK 200 million in 2003.

Hydro Aluminium

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**69,152**	65,051	51,083
Operating Income	**2,456**	1,698	185
EBITDA	**6,498**	4,334	2,543
Gross Investment	**70,357**	63,833	42,819
CROGI	**8.6%**	7.1%	5.7%
Number of employees	**26,728**	27,110	16,244

The Aluminium business area is comprised of the sub-segments Metals (Primary Metals and Metal Products), Rolled Products, Extrusion and Automotive (including the North America activities).

Summary of key developments in 2003

Aluminium s major strategic drive in the last few years has been to improve competitiveness by generating greater economies of scale (through acquisitions and expansions) and reducing costs.

During the first quarter of 2002, Hydro acquired VAW Aluminium AG (VAW) and the French building systems company, Technal. Hydro s consolidated results include the operating results of VAW as of 15 March 2002 and Technal, as of 26 January 2002.

Improvement programs were initiated in 2001 and 2002 to improve operating results, including reductions of annual costs, by NOK 2.5 billion compared to the combined cost level of VAW and Hydro Aluminium businesses in 2001. The target was achieved at end of the fourth quarter of 2003. This means the full year effect for 2004 will be in line with the target of NOK 2.5 billion. The accumulated cost of the program was NOK 1,166 million (NOK 176 million for 2003) which was NOK 397 million below the original cost estimate.

Since 2002, other improvement programs have been instituted. For example, Rolled Products established in 2003 an improvement program for the Holmestrand, Norway plant to reduce annual fixed costs by approximately NOK 80 million. The program includes manning reductions of 80 persons, representing approximately 16 percent of the total work force by the end of 2004. About 80 percent of the reductions were completed at the end of 2003.

Emission standards established by the Norwegian Pollution Authority require production facilities using Søderberg technology in the Høyanger and Årdal primary aluminium plants to be closed or replaced by 2006. After an extensive assessment, Hydro determined that investments to replace this capacity will not be made. The resulting closures will reduce the Company s annual primary aluminium production capacity by 72,000 tonnes. The affected parts of the facilities will be fully depreciated as of the closure date. A project to evaluate the impact of the closures on manning, restructuring and other sustainability issues relating to the locations was established. This work was expanded to look at the overall competitive position of Hydro Aluminium s European smelters and concluded upon subsequent to year end. For additional information see Outlook below.

Investments: Hydro Aluminium s brownfield expansion projects are all progressing according to plan and within budget. The expansion of the 50 percent-owned Søral primary aluminium plant was brought to full capacity in the first quarter of 2003. The expansion project for the aluminium plant in Sunndal, Norway, has completed the start up the first two sections of the new capacity and will phase in the remainder, with completion expected in the autumn of 2004. As a result of the Sunndal and Søral expansions Hydro s annual primary aluminium production will increase by approximately 190,000 tonnes per year in 2005 when both plants are at full production compared with 2001.

The first expansion of Alunorte, a low cost alumina refinery located in Brazil, was completed in early April 2003. An important strategic step for Hydro Aluminium in 2003 was the decision to participate in the second expansion of Alunorte. The expansion will provide Hydro with an additional 610,000 tonnes of alumina annually beginning from the second quarter of 2006. The expansion will increase Hydro Aluminium s raw material supply secured by equity investments.

An investment in a greenfield plant for Automotive precision tubing products was approved. The plant will be built in the strategically important market of China with a start up in 2005. Total investment is estimated to be NOK 150 million.

Divestment: Aluminium disposed of its interest in the aluminium recycling plant, VAW-IMCO in Germany. The disposal had no material income statement effect. Hydro has also entered into an agreement to sell its German based alumina business including Aluminium Oxid Stade GmbH an alumina refinery located in Stade, near Hamburg in Northern Germany. About half of Hydro s share of alumina from this facility is chemical grade alumina used in a variety of applications in the chemical and other industries, which are non-core to Hydro s aluminium activities. The transaction will not result in any significant gain or loss for Hydro.

Contracts: Hydro Aluminium s alumina balance was strengthened with a long-term supply contract with Comalco Aluminium Limited, a wholly owned subsidiary of Rio Tinto, entered into in 2003. Starting in 2005, Comalco will supply 300,000 tonnes of alumina annually to Hydro s Australian smelter operations. This increases to 500,000 tonnes annually from 2006 to 2030. The contract improves Hydro Aluminium s competitive position by securing the long-term availability of alumina in line with industrial long-term market prices.

A new long-term agreement with Talum in Slovenia will supply Hydro Aluminium with 70,000 tonnes of foundry alloy products per year starting in 2004 through 2010. The agreement enhances Hydro Aluminium s metal supplier concept built on a combination of equity primary aluminium production, recycling and remelt facilities and third party supply contracts.

Aluminium s Automotive segment strengthened its position by concluding important sales contracts. Beginning in 2006, rear bumper components will be delivered for the Citroen Picasso with an expected volume of 300,000 parts annually. In addition, Hydro will deliver an estimated volume of 1.2 million parts per year related to the front and rear bumper beams, including crash boxes on the rear bumper, for Audi s redesigned A4 model starting in 2004.

Technal, one of Extrusion s three primary building system s brands, has been selected as the supplier of aluminium building solutions for several new sports stadiums in Portugal. Portugal is hosting the 2004 European Football Championship and is in process of building a number of state-of-the-art football stadiums for the event.

The change in operating income for 2003 compared to the prior year and the most important items affecting the change are included in the table below:

Amounts in NOK million	
Operating income 2003	2,456
Operating income 2002	1,698
Change in Operating Income	758
Margin	(560)
Hedging	325
Volume	860
Fixed costs	(345)
Depreciation	(515)
Infrequent items and restructuring costs	615
Trading	460
Unrealized LME-effects	(310)
New / disposed business	285
Other	(57)
Total change in Operating Income	758

Variance Analysis

Aluminium s operating income for 2003 was NOK 2,456 million compared to NOK 1,698 million in the prior year. The higher result was due to the inclusion of VAW and Technal (new business) for the entire first quarter of 2003 and lower infrequent items compared to 2002. Excluding the variance for new business for the first quarter and infrequent items, operating income declined approximately NOK 143 million. The largest single variable explaining the decrease was lower aluminium prices measured in Norwegian kroner. This was marginally offset by translation effects on operating income of the strengthening of subsidiary currencies (mainly EUR) to Norwegian kroner.

Margins, excluding the effect of hedge programs, were lower and negatively impacted results by approximately NOK 560 million compared with 2002. Margins improved for Rolled Products and Extrusion but were weaker for Metals and Automotive. During 2003, aluminium prices measured in Norwegian kroner fell by seven percent compared with 2002 as a result of a lower average USD to NOK exchange rate. As a result, margins were substantially weaker in Metals compared to 2002 reducing results by approximately NOK 760 million. Realized effects of hedge programs in Metals positively impacted the results by NOK 323 million compared to 2002.

Higher volumes contributed an additional NOK 860 million to operating income compared to 2002. With the exception of North American activities, volumes increased for all sub-segments. The ramp up of new capacity in Metals, Automotive and, to a lesser extent, in Rolled Products was the fundamental reason for the improvement.

During 2003, new production capacity was also the major reason for higher fixed cost and depreciation that more than offset the savings from improvement programs. Fixed costs measured in NOK for European subsidiaries were negatively impacted by a stronger EUR to NOK. However, for operating income as a whole this currency translation effect was positive.

Metals realized results of trading activities were higher mainly due to currency gains on EUR denominated revenues measured in NOK. This was largely offset by lower unrealized results from the mark to market adjustments on Aluminium s LME derivative portfolio compared with 2002.

In order to better understand Hydro Aluminium s underlying performance, operating income has been adjusted for certain items referred to as infrequent items (see discussion under Non-recurring or infrequent items included in the Financial Review).

Net infrequent charges[1)] (including restructuring) impacting operating income for 2003 were NOK 94 million compared with NOK 708 million for 2002[2)].

EBITDA for 2003 was NOK 2,164 million higher in the year largely due to the inclusion of VAW for the entire period of 2003 and due to lower infrequent and restructuring items. Results from non-consolidated investees included unrealized currency gains on USD-denominated loans held by a Brazilian company, Alunorte, of NOK 218 million for 2003 compared to a loss of NOK 461 million for 2002. Excluding the new business, the currency effects on Alunorte and infrequent items, EBITDA increased NOK 288 million reflecting higher pre-tax cash flows from new capacity and higher trading results.

1) The major infrequent items for 2003 were NOK 140 million (USD 20 million) related to the loan loss provision on a subordinated loan provided to Goldendale Aluminium Inc., demanning and rationalization costs of approximately NOK 90 million, the reversal of an environmental accrual of NOK 59 million and the reversal of an accrual on a litigation settlement of NOK 77 million. Infrequent charges split by segment for 2003 were: Metals a gain of NOK 19 million; Rolled Products a charge of NOK 71 million; and Extrusion and Automotive a charge of NOK 42 million.
2) Infrequent charges (including restructuring) for 2002 mainly relate to manning reductions in connection with the improvement programs, VAW integration cost and higher cost of goods sold from VAW inventories due to the fair value adjustment as of the acquisition date. Metals downwardly revised restructuring accruals related to Magnesium by NOK by 10 million. Infrequent charges split by segment for 2002 were: Metals NOK 348 million; Rolled Products NOK 223 million and Extrusion and Automotive NOK 137 million.

Outlook

Economic indicators are increasingly positive for 2004, however, they continued to lead physical indicators (such as increased order and shipment levels) early in 2004. European market sentiment is positive but to a lesser degree than US indicators. The outlook for Asia remains strong.

Hydro s management expects that Western World shipments of primary aluminium will increase about five percent, equivalent to an estimated 1,000,000 tonnes in 2004 compared to 2003. Western World production, net of announced closures, is expected to increase by 500,000 tonnes in 2004. This is expected to improve the market balance. In the beginning of 2004, there has been a tight supply relative to demand for alumina which has resulted in a substantial increase in alumina prices in the spot market. In addition, electricity prices in the North Western US also remain relatively high. Due to both of these factors, the likelihood of significant restarts in closed production in the North Western US is reduced. Furthermore, if alumina spot prices remain at levels similar to those in early 2004, this may reduce incentives for starting up additional new capacity in China. China is dependent upon imports of this raw material. In addition, Chinese authorities announced a reduction of available credit for industrial development in China during the first quarter of 2004.

According to CRU International Ltd. (CRU), consumption of flat rolled products, extruded and automotive products is expected to grow compared to 2003. Growth projections for 2004 vary both by product and market, but range between 2 to 3.5 percent for North America and Western Europe.

Hydro obtains most of its alumina from companies in which it has an equity investment and through long-term contracts, usually based upon an LME price formula. Kaiser Aluminum filed motions at the end of January, 2004 in a US bankruptcy court seeking to reject or nullify certain alumina supply agreements. Neither Hydro nor any of its subsidiaries were named in this process. However, one of Hydro s Australian subsidiaries has an alumina supply agreement with Kaiser through 2005. Should Kaiser fail to deliver under contract terms, the alumina costs for the subsidiary could increase. In recent rulings by the US bankruptcy court, Kaiser has failed to obtain authorization for the rejection of certain alumina supply agreements. Accordingly, the risk of non-performance for Hydro s agreement is perceived as limited. In order to retain and improve its competitive position, Hydro s strategy has been to improve the relative cost position of its smelter system through continuous improvements and reduced cost within its existing capacity and expanding capacity at low cost smelters. Hydro s Norwegian smelters face challenges in reaching acceptable cost levels. Approximately 30 percent of production cost relates to direct and indirect labor. A combination of higher wages, social benefits, shift schedules, higher manning for support functions and higher prices for purchased services in Norway result in a cost disadvantage for these smelters. As a result, on May 7, 2004, the Board of Directors decided to recommend to the Corporate Assembly a plan aimed at reducing annual costs by NOK 350 to NOK 400 million. The plan will require a reduction of manning by about 800 employees in the Norwegian plants. The total estimated cost of the program, including manning reductions, is expected to be approximately NOK 800 million. The reduction in manning is expected to be completed by the end of the first quarter of 2005.

Due to low volume and declining profitability at the Casting plant in Leeds, UK, Aluminium s automotive sector entered into a consultation period starting September 18 with employees to evaluate a potential closure of the plant. The consultation period ended in December with a conclusion that the future of the plant was unlikely to be secured. A final decision was made June 2004 to close the plant in late 2004 or early 2005 with resulting closure costs of about NOK 265 million (GBP 22 million). This is net of expected proceeds from the sale of property and equipment. In addition, the plant is expected to show a negative EBITDA for 2004 of approximately NOK 44 million (GBP 3.6 million). Most of the plant staff of around 580 people will leave during the second half of 2004.

Production of turbo cylinder heads for GM will be relocated to Hydro s plant in Gyør, Hungary.

Metals

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**39,923**	39,646	31,475
Operating Income	**2,293**	1,690	372
EBITDA	**4,298**	2,703	1,766
Gross Investment	**38,896**	34,905	26,330
CROGI	**9.8%**	7.1%	6.0%
Number of employees	**6,276**	6,284	4,561

Market conditions

Western World shipments of primary metal grew an estimated 4.6 percent for 2003 compared to the same period of the prior year. This was an increase from 2.6 percent in 2002 versus 2001 when industrial activity was at a low level. For 2003, most of the shipment growth is believed to have been attributable to strong demand in Asia while growth in Western Europe and North America were modest for the year. China s internal consumption continued to grow rapidly in 2003. However, new Chinese capacity coming on stream outpaced internal consumption. China increased its net primary exports to the Western World by an estimated 100,000 tonnes in 2003 to a total of about 350,000 tonnes. China continued to have net imports of scrap, aluminium semi-finished products (mainly rolled and extruded products) and finished products of approximately 600,000 tonnes in 2003.

Western World Production increased approximately 3.0 percent (520,000 tonnes) due to new capacity net of closures. In 2003, Alcoa reported the closure of 95,000 tonnes of production in its West Ferndale smelter in the US.

Reported inventories at the end of the year were about three percent (100,000 tonnes) higher than at the end of 2002. There is uncertainty in the trends for unreported inventories, however, indications are that they increased more than reported inventories. The average market price for aluminium (LME 3 monthly average) was USD 1,428 per tonne for 2003, which was USD 63 per tonne higher compared with 2002.

Revenues

Metals revenues were positively impacted by the consolidation of VAW for the full first quarter of 2003 compared with 15 days in the first quarter of 2002. Volumes for Hydro Aluminium s primary metal increased 18 percent to a total of 1,473,000 tonnes in 2003 compared to the same period of 2002. This reflected both the inclusion of VAW for the entire first quarter of 2003 as well as new capacity from Sunndal.

Excluding the variance for VAW for the first quarter, operating revenues declined approximately 10 percent or NOK 4 billion. Lower realized prices measured in Norwegian kroner more than offset higher volumes from the Sunndal expansion.

Hydro realized an aluminium price of USD 1,440 per tonne for 2003 compared to USD 1,372 per tonne for the same period of 2002. Measured in Norwegian kroner, however, the realized aluminium price declined by over seven percent. The realized NOK/USD exchange rate was NOK 7.25 for 2003 (NOK 8.21 in 2002). The realized price includes the effect of hedges.

Realized effects of hedge programs[3)], which are comprised of LME future contracts and US dollar forward contracts, positively impacted the results by about NOK 476 million in 2003 (NOK 153 million in 2002) of which about NOK 240 million related to Sunndal in 2003. LME future contracts relating to the Sunndal program are spread evenly over the quarters while the amount of US dollar forward contracts vary by quarter.

Product premiums (particularly for extrusion ingot) were noticeably higher in USD but less pronounced stated in Norwegian kroner.

Operating costs

Excluding the VAW variance for the first quarter, raw material and energy cost (variable costs) declined in spite of higher volumes from new capacity mainly due to the effect of reduced alumina cost (measured in NOK) and a one-off positive adjustment to tolling fees for raw materials of NOK 34 million. Fixed cost[4)] and depreciation rose compared to 2002 reflecting the new capacity. Depreciation also included a write down of assets of NOK 20 million.

Operating income

Operating income for 2003 amounted to NOK 2,293 million compared to NOK 1,690 million in the prior year. Excluding VAW activities for the first quarter, restructuring and infrequent items, operating income weakened NOK 69 million. Changes in product prices and currency rates resulted in a reduction in margins of about NOK 760 million compared with 2002. However, this was mitigated by positive effects from certain hedge programs (NOK 323 million) and improved trading results (NOK 460 million). Trading results improved mainly due to currency gains. Improvement resulting from higher sales volumes was offset by higher fixed cost and depreciation.

EBITDA

EBITDA for 2003 was NOK 4,298 million. Excluding VAW activities for the first quarter, infrequent items and currency effects for Alunorte, EBITDA was NOK 139 million higher than the corresponding period of 2002. Improved volumes, results of hedging programs and trading more than offset the fall in margins and higher fixed cost.

3) Both the LME and currency hedges related to the Sunndal program are designated as cash flow hedges against production. Changes in the fair value of the contracts are included in Other Comprehensive Income while the realized amounts are included in revenues. Sunndal accounts for the largest part of the hedge program. In addition, Metals economically hedges certain revenues and raw materials in terms of LME prices with the purpose of locking in margins on such transactions. These positions referred to as price hedges do not qualify for hedge accounting. Realized aluminium price hedges are included in revenues or raw material costs while unrealized effects are included at the Hydro Aluminium level under Other and eliminations. Related currency effects are classified as financial items and excluded from operating income. Price hedges are excluded from the numbers for the hedge programs disclosed above.

4) Fixed cost excludes variable production inputs (such as raw materials & energy), depreciation and miscellaneous gains & losses on disposals of assets.

Rolled Products

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**18,377**	14,790	4,228
Operating Income	**132**	(295)	58
EBITDA	**835**	258	162
Gross Investment	**12,645**	11,937	2,626
CROGI	**6.4%**	3.5%	5.8%
Number of employees	**4,259**	4,306	766

Market conditions

Difficult market conditions continued in Europe in 2003. According to CRU, consumption of flat rolled products in Europe was almost unchanged compared to 2002. Average capacity utilization for the European industry improved marginally but remained relatively low at about 83 percent.

The North American market had an increase in consumption of about one percent for the year as a whole compared to 2002. Capacity utilization for the US industry improved about two percent to approximately 74 percent. The stronger EURO compared to USD was a disadvantage to producers outside the US for export sales. The EUR/USD exchange rate impacts export pricing of flat rolled products in Asia, South and North America which are typically based on a USD formula and put pressure on margins.

Litho and foil are higher margin products. Automotive flat rolled products, especially body-in white parts, are important to the industry as these products are expected to have attractive growth rates. Many flat rolled products are relatively mature in European and North American markets.

Revenues

Rolled Product s revenues included consolidation of VAW for an additional 2 1/2 months in 2003 compared with 2002. External shipments[5)], on a proforma basis including comparable VAW figures for the full year of 2002, increased around seven percent to 893,000 tonnes. Higher volumes were in part due to the ramp up of new capacity. The total growth in shipments for 2003 over 2002 was distributed between Hydro s product groups as follows: Litho (2 percent), Foil (1 percent), Automotive (1 percent) and Strip (3 percent).

Operating revenues, excluding the VAW variance for the first quarter, increased approximately three percent or about NOK 450 million. This was mainly due to a volume increase of around five percent that was partially offset by the impact of lower EUR revenues for USD denominated export sales. Rolled Products exports about 19 percent of its sales to Asia, South and North America. The EUR strengthened 20 percent to the USD in 2003.

Rolled Products major activities are denominated in EUR and all sales revenues are price hedged in terms of aluminium prices and foreign currency using commodity and financial instruments. Realized gains related to aluminium price hedges are included in revenues while currency effects are included in financial items.

Operating costs

Excluding the VAW variance for the first quarter and infrequent items, Rolled Products variable cost, fixed cost and depreciation increased in 2003 primarily as a result of increased volumes.

Rolled Products cost structure varies with changes in the aluminium price and its product mix. On average, the metal price comprised about 60 percent of total cost while other materials and energy account for about 20 percent of the total. Higher variable costs due to increased sales volumes were largely offset by lower aluminium prices stated in EUR and lower losses on inventory.

Rolled Products sales prices are based on a margin over the metal price. The production process requires a long lead time of between two to three months. Therefore, cost of goods sold (and margins) are impacted by variances in inventory values resulting from changing aluminium prices. Falling prices in EUR increase cost (reduce margins) while increasing prices have the opposite effect. In 2003, the loss on inventory was approximately NOK 120 million compared with approximately NOK 200 million in 2002.

Fixed cost and depreciation rose compared to 2002 reflecting the new capacity (automotive line in Germany) and investment in Malaysia) which more than offset savings from improvement programs and the reversal of an accrual for a resolved claim of NOK 52 million.

Operating income

Operating income for 2003 was NOK 132 million compared to a loss of NOK 295 million in the previous year. Approximately NOK 10 million of the increase in operating income resulted from the inclusion of the activities of the former VAW, which were not consolidated for the entire year of 2002. Excluding infrequent items, operating income was NOK 203 million, an improvement of NOK 275 million. Improved margins positively impacted results by approximately NOK 240 million compared with 2002. Increased shipments contributed around NOK 195 million to results but this was largely offset by increased fixed cost and depreciation.

EBITDA

EBITDA for Rolled Products for 2003 was NOK 835 million compared to NOK 258 million for 2002. Excluding infrequent items, EBITDA was NOK 906 million (NOK 481 million in 2002), an improvement of NOK 425 million. Approximately NOK 112 million of this improvement resulted from the inclusion of the activities of the former VAW, which were not consolidated for the entire period of 2002. The remainder of the improvement was principally due to higher margins and shipments.

5) Excludes wire rod shipments.

Extrusion and Automotive

Amounts in NOK million	**2003**	2002	2001
Operating Revenues	**24,529**	24,245	22,487
Operating Income	**98**	14	(228)
EBITDA	**1,432**	1,084	632
Gross Investment	**18,737**	16,846	14,011
CROGI	**7.9%**	7.0%	4.5%
Number of employees	**16,193**	16,520	10,917

Market conditions

The overall market for general extrusion in Europe showed improvement towards the end of 2003 but apparent consumption was a modest increase of one percent for 2003 as a whole (CRU). The building and construction market in Germany remained difficult resulting in pressure on volumes. For extruded products in North America, CRU reported a reduction in apparent consumption in 2003 of about one percent. Global light vehicle sales were reported to be approximately 0.5 percent higher than in 2002. However, Western European and North American automotive markets, which are the most relevant to Hydro, lagged behind the global averages with a reduction in light vehicle sales of two and one half percent, respectively.

Revenues

Operating revenues included the consolidation of VAW and Technal for the full year of 2003 compared with the period after the acquisition dates in the first quarter of 2002.

Excluding the variance in the first quarter from VAW and Technal (new business), revenues declined about three percent (NOK 700 million). This was due in part to negative translation effects. North American revenues fell in NOK as a result of the 12 percent lower NOK / USD exchange rate in 2003 compared to 2002. This was largely offset by the opposite translation effect on revenues of a stronger EUR to NOK for European subsidiaries. Automotive revenues and sales volumes increased compared to 2002, principally due to the ramp up of shipments on new contracts. Higher volumes offset the lower revenues from price pressure on heat transfer and crash management components, although margins were negatively affected. Extrusion s revenues were somewhat lower. Although European extrusion shipments were somewhat higher, shipments declined for Hydro s Building systems operations due to low demand in the European construction industry. In North America, revenues fell as shipment volumes declined from own production (lower demand) and third party trading (which was largely discontinued) in 2003 compared to the same period last year.

Operating costs

Excluding new business and infrequent items, variable costs declined while fixed cost and depreciation increased. In total, cost development in 2003 benefited from movement in currencies in translation (the opposite effect as variance for revenues) compared with 2002.

Variable costs increased for Automotive, driven by higher volumes, but declined for Extrusion and North America. Fixed costs increased in 2003 due to higher activity in Automotive and net translation effects that were partially offset by cost reduction from improvement programs in North America. Depreciation expense increased due to start up of new automotive production lines and North American remelt operations and write downs of NOK 79 million relating to Automotive fixed assets.

Operating income

Operating income for 2003 was NOK 98 million compared to NOK 14 million in the prior year. Excluding the variance relating to VAW and Technal, for the first quarter of 2003 and infrequent items, operating income was NOK 148 million (NOK 151 million). Slightly higher margins and improved volumes contributed positively to results. This positive effect was offset by the higher fixed costs and depreciation expense. Operating income benefited somewhat from translation effects compared with 2002.

Operating income for Extrusion improved in a difficult market. North American operations have made substantial improan; font-size:10pt">

Total

55 $67,306 $35,919 $13,506 $11,457 $60,882

Table of Contents

The following is a presentation of non-covered TDR s on non-accrual status as of September 30, 2013 and December 31, 2012 because they are not in compliance with the modified terms:

	September 30, 2013			December 31, 2012		
	Number of Loans		Recorded Balance	Number of Loans		Recorded Balance
	(Dollars in thousands)					
Real estate:						
Commercial real estate loans						
Non-farm/non-residential		$		2	$	761
Residential real estate loans						
Residential 1-4 family	6		1,363	5		2,665
Multifamily residential	1		69			
Total real estate	7		1,432	7		3,426
Total	7	$	1,432	7	$	3,426

Allowance for Loan Losses and Credit Quality for Covered Loans

During the second quarter of 2013, impairment testing on the estimated cash flows of the covered loans established that one pool evaluated had experienced material projected credit deterioration. As a result, the Company recorded a $500,000 provision for loan losses to the allowance for loan losses related to the purchased impaired loans during the three-month period ended June 30, 2013. Since these loans are covered by loss share with the FDIC, the Company was able to increase its indemnification asset by $400,000 resulting in a net provision for loan losses of $100,000.

During the second quarter of 2012, impairment testing on the estimated cash flows of the covered loans established that two pools evaluated had experienced material projected credit deterioration. As a result, the Company recorded a $6.6 million provision for loan losses to the allowance for loan losses related to the purchased impaired loans during the three-month period ended June 30, 2012. Since these loans are covered by loss share with the FDIC, the Company was able to increase its indemnification asset by $5.3 million resulting in a net provision for loan losses of $1.3 million.

During the third quarter of 2012, impairment testing on the estimated cash flows of the covered loans established that two pools evaluated had experienced projected credit deterioration. As a result, the Company recorded an $837,000 provision for loan losses to the allowance for loan losses related to the purchased impaired loans during the three-month period ended September 30, 2012. Since these loans are covered by loss share with the FDIC, the Company was able to increase its indemnification asset by $670,000 resulting in a net provision for loan losses of $167,000.

Table of Contents

The following tables present the balance in the allowance for loan losses for the covered loan portfolio for the three and nine-month periods ended September 30, 2013, and the allowance for loan losses and recorded investment in loans covered by FDIC loss share based on portfolio segment by impairment method as of September 30, 2013.

	Three Months Ended September 30, 2013						
	Construction/ Land Development	Other Commercial Real Estate	Residential Real Estate	Commercial & Industrial	Consumer & Other	Unallocated	Total
	(In thousands)						
Allowance for loan losses:							
Beginning balance	$ 161	$ 472	$ 286	$ 33	$	$	$ 952
Loans charged off							
Recoveries of loans previously charged off	15	6	133				154
Net loans recovered (charged off)	15	6	133				154
Provision for loan losses before benefit attributable to FDIC loss share agreements	(35)	84	(55)	6			
Benefit attributable to FDIC loss share agreements	28	(67)	44	(5)			
Net provision for loan losses	(7)	17	(11)	1			
Increase in FDIC indemnification asset	(28)	67	(44)	5			
Balance, September 30	$ 141	$ 562	$ 364	$ 39	$	$	$ 1,106

	Nine Months Ended September 30, 2013						
	Construction/ Land Development	Other Commercial Real Estate	Residential Real Estate	Commercial & Industrial	Consumer & Other	Unallocated	Total
	(In thousands)						
Allowance for loan losses:							
Beginning balance	$ 1,169	$ 4,005	$ 228	$ 60	$	$	$ 5,462
Loans charged off	(720)	(3,426)	(724)	(157)			(5,027)
Recoveries of loans previously charged off	15	13	143				171
Net loans recovered (charged off)	(705)	(3,413)	(581)	(157)			(4,856)
	(323)	(30)	717	136			500

Provision for loan losses before benefit attributable to FDIC loss share agreements													
Benefit attributable to FDIC loss share agreements		258		24		(573)		(109)					(400)
Net provision for loan losses		(65)		(6)		144		27					100
Increase in FDIC indemnification asset		(258)		(24)		573		109					400
Balance, September 30	$	141	$	562	$	364	$	39	$		$		$ 1,106

	As of September 30, 2013						
	Construction/ Land Development	Other Commercial Real Estate	Residential Real Estate	Commercial & Industrial	Consumer & Other	Unallocated	Total
	(In thousands)						
Allowance for loan losses:							
Period end amount allocated to:							
Loans individually evaluated for impairment	$	$	$	$	$	$	$
Loans collectively evaluated for impairment							
Loans evaluated for impairment balance, September 30							
Purchased credit impaired loans acquired	141	562	364	39			1,106
Balance, September 30	$ 141	$ 562	$ 364	$ 39	$	$	$ 1,106
Loans receivable:							
Period end amount allocated to:							
Loans individually evaluated for impairment	$	$	$	$	$	$	$
Loans collectively evaluated for impairment							
Loans evaluated for impairment balance, September 30							
Purchased credit impaired loans acquired	51,492	136,096	113,198	6,291	995		308,072

Balance, September 30	$ 51,492	$ 136,096	$ 113,198	$ 6,291	$ 995	$	$ 308,072

27

Table of Contents

The following tables present the balance in the allowance for loan losses for the covered loan portfolio for the nine-month period ended September 30, 2012 and the year ended December 31, 2012, and the allowance for loan losses and recorded investment in loans covered by FDIC loss share based on portfolio segment by impairment method as of December 31, 2012.

	Year Ended December 31, 2012						
	Construction Land Development	Other Commercial Real Estate	Residential Real Estate	Commercial & Industrial	Consumer & Other	Unallocated	Total
	(In thousands)						
Allowance for loan losses:							
Beginning balance	$	$	$	$	$	$	$
Loans charged off			(76)		(278)		(354)
Recoveries of loans previously charged off							
Net loans recovered (charged off)			(76)		(278)		(354)
Provision for loan losses before benefit attributable to FDIC loss share agreements	1,531	5,245	370	78	278		7,502
Benefit attributable to FDIC loss share agreements	(1,225)	(4,197)	(296)	(62)	(222)		(6,002)
Net provision for loan losses	306	1,048	74	16	56		1,500
Increase in FDIC indemnification asset	1,225	4,197	296	62	222		6,002
Balance, September 30	1,531	5,245	294	78			7,148
Loans charged off	(648)	(970)	(56)	(14)			(1,688)
Recoveries of loans previously charged off			2				2
Net loans recovered (charged off)	(648)	(970)	(54)	(14)			(1,686)
Provision for loan losses before benefit attributable to FDIC loss share agreements	286	(270)	(12)	(4)			
Benefit attributable to FDIC loss share agreements	(229)	217	10	2			
Net provision for loan losses	57	(53)	(2)	(2)			
Increase in FDIC indemnification asset	229	(217)	(10)	(2)			
Balance, December 31	$ 1,169	$ 4,005	$ 228	$ 60	$	$	$ 5,462

	As of December 31, 2012						
	Construction Land Development	Other Commercial Real Estate	Residential Real Estate	Commercial & Industrial	Consumer & Other	Unallocated	Total
	(In thousands)						
Allowance for loan losses:							
Period end amount allocated to:							
Loans individually evaluated for impairment	$	$	$	$	$	$	$
Loans collectively evaluated for impairment							
Loans evaluated for impairment balance, December 31							
Purchased credit impaired loans acquired	1,169	4,005	228	60			5,462
Balance, December 31	$ 1,169	$ 4,005	$ 228	$ 60	$	$	$ 5,462
Loans receivable:							
Period end amount allocated to:							
Loans individually evaluated for impairment	$	$	$	$	$	$	$
Loans collectively evaluated for impairment							
Loans evaluated for impairment balance, December 31							
Purchased credit impaired loans acquired	66,713	167,005	135,192	14,668	1,306		384,884
Balance, December 31	$ 66,713	$ 167,005	$ 135,192	$ 14,668	$ 1,306	$	$ 384,884

28

Table of Contents

Changes in the carrying amount of the accretable yield for purchased credit impaired loans acquired were as follows for the nine-month period ended September 30, 2013 for the Company s covered and non-covered acquisitions:

	Accretable Yield	Carrying Amount of Loans
	(In thousands)	
Balance at beginning of period	$ 127,371	$ 612,956
Reforecasted future interest payments for loan pools	9,159	
Accretion	(42,450)	42,450
Adjustment to yield	15,566	
Transfers to foreclosed assets held for sale covered by FDIC loss share		(11,103)
Payments received, net		(154,612)
Balance at end of period	$ 109,646	$ 489,691

The loan pools were evaluated by the Company and are currently forecasted to have a slower run-off than originally expected. As a result, the Company has reforecast the total accretable yield expectations for those loan pools by $9.2 million. This updated forecast does not change the expected weighted average yields on the loan pools.

Five pools evaluated by the Company were determined to have a materially projected credit improvement. As a result of this improvement, the Company will recognize approximately $15.6 million as an adjustment to yield over the weighted average life of the loans. Improvements in credit quality decrease the basis in the related indemnification assets. This positive event will reduce the indemnification asset by approximately $12.5 million and increase our FDIC true-up liability by $1.6 million. The $12.5 million will be amortized over the weighted average life of the loans or the life of the shared-loss agreements, whichever is shorter. The amortization will be shown as a reduction to FDIC indemnification non-interest income. The $1.6 million will be expensed over the remaining true-up measurement date as other non-interest expense. This will result in approximately $4.7 million of pre-tax net income being recognized going forward which may or may not be symmetrical depending on the weighted average life of the loans.

7. Goodwill and Core Deposits and Other Intangibles

Changes in the carrying amount and accumulated amortization of the Company s goodwill and core deposits and other intangibles at September 30, 2013 and December 31, 2012, were as follows:

	September 30, 2013	December 31, 2012
	(In thousands)	
Goodwill		
Balance, beginning of period	$ 85,681	$ 59,663
Vision and Premier acquisitions		26,018

Balance, end of period	$ 85,681	$ 85,681

	September 30, 2013	December 31, 2012
	(In thousands)	
Core Deposit and Other Intangibles		
Balance, beginning of period	$ 12,061	$ 8,620
Vision Bank acquisition		3,190
Amortization expense	(2,406)	(2,018)
Balance, September 30	$ 9,655	9,792
Premier and Heritage acquisitions		3,012
Amortization expense		(743)
Balance, end of year		$ 12,061

29

Table of Contents

The carrying basis and accumulated amortization of core deposits and other intangibles at September 30, 2013 and December 31, 2012 were:

	September 30, 2013	December 31, 2012
	(In thousands)	
Gross carrying basis	$ 29,663	$ 29,663
Accumulated amortization	(20,008)	(17,602)
Net carrying amount	$ 9,655	$ 12,061

Core deposit and other intangible amortization expense was approximately $802,000 and $694,000 for the three-months ended September 30, 2013 and 2012, respectively. Core deposit and other intangible amortization expense was approximately $2.4 million and $2.0 million for the nine-months ended September 30, 2013 and 2012, respectively. As of September 30, 2013, HBI s estimated amortization expense of core deposits and other intangibles for each of the years 2013 through 2017 is approximately: 2013 $3.2 million; 2014 $3.1 million; 2015 $2.2 million; 2016 $973,000; 2017 $884,000. These projections exclude the previously announced Liberty Bancshares, Inc. (Liberty) acquisition.

The carrying amount of the Company s goodwill was $85.7 million at both September 30, 2013 and December 31, 2012. Goodwill is tested annually for impairment during the fourth quarter. If the implied fair value of goodwill is lower than its carrying amount, goodwill impairment is indicated and goodwill is written down to its implied fair value. Subsequent increases in goodwill value are not recognized in the financial statements.

8. Other Assets

Other assets consists primarily of FDIC claims receivable, equity securities without a readily determinable fair value and other miscellaneous assets. As of September 30, 2013 and December 31, 2012 other assets were $66.5 million and $75.7 million, respectively.

An indemnification asset was created when the Company acquired FDIC covered loans. The indemnification asset represents the carrying amount of the right to receive payments from the FDIC for losses incurred on specified assets acquired from failed insured depository institutions or otherwise purchased from the FDIC that are covered by loss-sharing agreements with the FDIC. When the Company experiences a loss on the covered loans and subsequently requests reimbursement of the loss from the FDIC, the indemnification asset is reduced by the FDIC reimbursable amount. A corresponding claim receivable is consequently recorded in other assets until the cash is received from the FDIC. The FDIC claims receivable was $31.2 million and $45.2 million at September 30, 2013 and December 31, 2012, respectively.

The Company has equity securities without readily determinable fair values. These equity securities are outside the scope of ASC Topic 320, *Investments-Debt and Equity Securities*. They include items such as stock holdings in Federal Home Loan Bank, Federal Reserve Bank, Bankers Bank and other miscellaneous holdings. The equity securities without a readily determinable fair value were $27.1 million and $20.2 million at September 30, 2013 and December 31, 2012, respectively and are accounted for at cost.

9. Deposits

The aggregate amount of time deposits with a minimum denomination of $100,000 was $434.8 million and $549.1 million at September 30, 2013 and December 31, 2012, respectively. Interest expense applicable to certificates in excess of $100,000 totaled $766,000 and $1.7 million for the three months ended September 30, 2013 and 2012, respectively. Interest expense applicable to certificates in excess of $100,000 totaled $2.8 million and $6.3 million for the nine months ended September 30, 2013 and 2012, respectively. As of September 30, 2013 and December 31, 2012, brokered deposits were $23.8 million and $56.9 million, respectively.

Deposits totaling approximately $436.9 million and $484.4 million at September 30, 2013 and December 31, 2012, respectively, were public funds obtained primarily from state and political subdivisions in the United States.

Table of Contents

10. Securities Sold Under Agreements to Repurchase

At September 30, 2013 and December 31, 2012, securities sold under agreements to repurchase totaled $71.3 million and $66.3 million, respectively. For the three-month periods ended September 30, 2013 and 2012, securities sold under agreements to repurchase daily weighted average totaled $73.9 million and $64.8 million, respectively. For the nine-month periods ended September 30, 2013 and 2012, securities sold under agreements to repurchase daily weighted average totaled $72.1 million and $68.4 million, respectively.

11. FHLB Borrowed Funds

The Company s Federal Home Loan Bank (FHLB) borrowed funds were $270.2 million and $130.4 million at September 30, 2013 and December 31, 2012, respectively. At September 30, 2013, $170.0 million and $100.2 million of the outstanding balance were short-term and long-term advances, respectively. All of the outstanding balance at December 31, 2012 was long-term advances. The FHLB advances mature from the current year to 2025 with fixed interest rates ranging from 0.210% to 4.799% and are secured by loans and investments securities. Expected maturities will differ from contractual maturities, because FHLB may have the right to call or prepay certain obligations.

Additionally, at September 30, 2013, the Company had no amount in letters of credit under a FHLB blanket borrowing line of credit, which are used to collateralize public deposits at September 30, 2013. The Company had $90.5 million at December 31, 2012 in letters of credit under a FHLB blanket borrowing line of credit, which were used to collateralize public deposits at December 31, 2012.

12. Subordinated Debentures

Subordinated debentures at September 30, 2013 and December 31, 2012 consisted of guaranteed payments on trust preferred securities with the following components:

	September 30, 2013	December 31, 2012
	(In thousands)	
Subordinated debentures, issued in 2003, due 2033, fixed at 6.40%, during the first five years and at a floating rate of 3.15% above the three-month LIBOR rate, reset quarterly, thereafter. Retired during the first quarter of 2013.	$	$ 20,619
Subordinated debentures, issued in 2003, due 2033, floating rate of 3.15% above the three-month LIBOR rate, reset quarterly. Retired during the first quarter of 2013.		5,155
Subordinated debentures, issued in 2006, due 2036, fixed rate of 6.75% during the first five years and at a floating rate of 1.85% above the three-month LIBOR rate, reset quarterly, thereafter, currently callable without penalty	3,093	3,093

Total	$ 3,093	$ 28,867

The trust preferred securities are tax-advantaged issues that qualify for Tier 1 capital treatment subject to certain limitations. Distributions on these securities are included in interest expense. Each of the trusts is a statutory business trust organized for the sole purpose of issuing trust securities and investing the proceeds in our subordinated debentures, the sole asset of each trust. The trust preferred securities of each trust represent preferred beneficial interests in the assets of the respective trusts and are subject to mandatory redemption upon payment of the subordinated debentures held by the trust. We wholly own the common securities of each trust. Each trust s ability to pay amounts due on the trust preferred securities is solely dependent upon our making payment on the related subordinated debentures. Our obligations under the subordinated securities and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by us of each respective trust s obligations under the trust securities issued by each respective trust.

Presently, the funds raised from the trust preferred offerings qualify as Tier 1 capital for regulatory purposes, subject to the applicable limit, with the balance qualifying as Tier 2 capital.

31

Table of Contents

The Company currently holds a $3.1 million trust preferred security which is currently callable without penalty based on the terms of the specific agreement.

During the first quarter of 2013, the Company made the election to pay off $25.8 million of subordinated debentures which had previously been approved by the Federal Reserve Bank of St. Louis. As a result of the Liberty acquisition, we are not projecting the Company to pay-off the remaining balance during 2013.

13. Income Taxes

The following is a summary of the components of the provision (benefit) for income taxes for the three and nine-month periods ended September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Current:				
Federal	$ 6,635	$ 10,619	$ 17,691	$ 23,331
State	1,342	2,100	3,563	4,501
Total current	7,977	12,719	21,254	27,832
Deferred:				
Federal	2,171	(3,096)	7,994	(1,757)
State	442	(615)	1,587	(349)
Total deferred	2,613	(3,711)	9,581	(2,106)
Provision for income taxes	$ 10,590	$ 9,008	$ 30,835	$ 25,726

The reconciliation between the statutory federal income tax rate and effective income tax rate is as follows for the three and nine-month periods ended September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Statutory federal income tax rate	35.00%	35.00%	35.00%	35.00%
Effect of nontaxable interest income	(2.01)	(2.40)	(2.06)	(2.53)
Cash value of life insurance	(0.34)	(0.28)	(0.25)	(0.33)
State income taxes, net of federal benefit	4.01	3.84	3.97	3.76
Other	(0.08)	(0.28)	(0.13)	(0.07)
Effective income tax rate	36.58%	35.88%	36.53%	35.83%

Table of Contents

The types of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts that give rise to deferred income tax assets and liabilities, and their approximate tax effects, are as follows:

	September 30, 2013	December 31, 2012
	(In thousands)	
Deferred tax assets:		
Allowance for loan losses	$ 15,225	$ 19,999
Deferred compensation	1,721	1,331
Stock options	277	231
Real estate owned	6,143	9,211
Loan discounts	35,914	51,946
Tax basis premium/discount on acquisitions	21,482	23,914
Unrealized loss on securities available-for-sale	881	
Deposits	324	485
Other	5,464	7,239
Gross deferred tax assets	87,431	114,356
Deferred tax liabilities:		
Accelerated depreciation on premises and equipment	2,253	377
Unrealized gain on securities available-for-sale		7,747
Core deposit intangibles	751	1,506
Indemnification asset	36,550	54,009
FHLB dividends	896	889
Other	936	2,830
Gross deferred tax liabilities	41,386	67,358
Net deferred tax assets	$ 46,045	$ 46,998

14. Common Stock and Compensation Plans

On April 18, 2013 at the Annual Meeting of Shareholders of the Company, the shareholders approved, as proposed in the Proxy Statement, an amendment to the Company s Restated Articles of Incorporation to increase the number of authorized shares of common stock from 50,000,000 to 100,000,000.

On April 18, 2013, our Board of Directors declared a two-for-one stock split to be paid in the form of a 100% stock dividend on June 12, 2013 (the Payment Date) to shareholders of record at the close of business on May 22, 2013. The additional shares were distributed by the Company s transfer agent, Computershare, and the Company s common stock began trading on a split-adjusted basis on the NASDAQ Global Select Market on June 13, 2013. The stock split increased the Company s total shares of common stock outstanding as of June 12, 2013 from 28,121,596 shares to 56,243,192 shares (split adjusted). All previously reported share and per share data included in filings subsequent to the Payment Date are restated to reflect the retroactive effect of this two-for-one stock split.

Stock Compensation Plans

The Company has a stock option and performance incentive plan known as the Amended and Restated 2006 Stock Option and Performance Incentive Plan (the Plan). The purpose of the Plan is to attract and retain highly qualified officers, directors, key employees, and other persons, and to motivate those persons to improve our business results. The Plan provides for the granting of incentive nonqualified options to purchase stock or for the issuance of restricted shares up to 4,644,000 shares (split adjusted) of common stock in the Company. At September 30, 2013, the Company has approximately 1,625,000 shares of common stock remaining available for grants or issuance under the plan and approximately 2,600,000 shares reserved for issuance of common stock.

Table of Contents

The intrinsic value of the stock options outstanding and stock options vested at September 30, 2013 was $21.4 million and $18.3 million, respectively. The intrinsic value of the stock options exercised during the three-month period ended September 30, 2013 was approximately $760,000. The intrinsic value of the stock options exercised during the nine-month period ended September 30, 2013 was approximately $896,000. Total unrecognized compensation cost, net of income tax benefit, related to non-vested awards, which are expected to be recognized over the vesting periods, was approximately $621,000 as of September 30, 2013. For the first nine months of 2013, the Company has expensed $108,000 for the non-vested awards.

The table below summarized the transactions under the Company s stock option plans (split adjusted) at September 30, 2013 and December 31, 2012 and changes during the nine-month period and year then ended:

	For the Nine Months Ended September 30, 2013		For the Year Ended December 31, 2012	
	Shares (000)	Weighted Average Exercisable Price	Shares (000)	Weighted Average Exercisable Price
Outstanding, beginning of year	871	$ 6.66	1,138	$ 5.68
Granted	150	18.23	90	13.13
Forfeited			(2)	4.65
Exercised	(46)	5.98	(355)	5.17
Outstanding, end of period	975	8.47	871	6.66
Exercisable, end of period	751	$ 6.07	766	$ 5.86

Stock-based compensation expense for stock-based compensation awards granted is based on the grant date fair value. For stock option awards, the fair value is estimated at the date of grant using the Black-Scholes option-pricing model. This model requires the input of highly subjective assumptions, changes to which can materially affect the fair value estimate. Additionally, there may be other factors that would otherwise have a significant effect on the value of employee stock options granted but are not considered by the model. Accordingly, while management believes that the Black-Scholes option-pricing model provides a reasonable estimate of fair value, the model does not necessarily provide the best single measure of fair value for the Company s employee stock options. The weighted-average fair value of options granted during the nine-months ended September 30, 2013 was $3.32 per share (split adjusted). The weighted-average fair value of options granted during the year ended December 31, 2012 was $3.59 per share (split adjusted). The fair value of each option granted is estimated on the date of grant using the Black-Scholes option-pricing model based on the weighted-average assumptions for expected dividend yield, expected stock price volatility, risk-free interest rate, and expected life of options granted.

	For the Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012
Expected dividend yield	1.54%	1.52%

Expected stock price volatility	20.93%	30.56%
Risk-free interest rate	1.19%	1.47%
Expected life of options	6.5 years	6.5 years

34

Table of Contents

The following is a summary of currently outstanding and exercisable options (split adjusted) at September 30, 2013:

	Options Outstanding			Options Exercisable	
Exercise Prices	Options Outstanding Shares (000)	Weighted-Average Remaining Contractual Life (in years)	Weighted-Average Exercise Price	Options Exercisable Shares (000)	Weighted-Average Exercise Price
$ 3.08 to $3.50	38	1.13	$ 3.20	38	$ 3.20
$ 3.92 to $4.34	55	1.62	4.23	55	4.23
$ 4.78 to $4.92	94	1.69	4.81	94	4.81
$ 5.33 to $5.33	199	2.10	5.33	199	5.33
$ 5.54 to $5.54	202	2.45	5.54	202	5.54
$ 8.32 to $8.60	84	4.28	8.57	84	8.57
$ 9.25 to $9.31	10	3.65	9.29	10	9.29
$ 10.16 to $11.37	55	3.55	10.33	53	10.29
$ 13.12 to $13.12	88	8.31	13.12	16	13.12
$ 17.25 to $19.08	150	9.44	18.23		
	975			751	

The table below summarized the activity for the Company s restricted stock issued and outstanding (split adjusted) at September 30, 2013 and December 31, 2012 and changes during the period and year then ended:

	As of September 30, 2013	As of December 31, 2012
	(In thousands)	
Beginning of year	269	97
Issued	35	208
Vested	(32)	(36)
Forfeited	(16)	
End of period	256	269
Amount of expense for nine months and twelve months ended, respectively	$ 781	$ 780

On August 2, 2012, 208,000 shares (split adjusted) of restricted common stock were issued to our named executive officers and certain other employees of the Company. These shares include 86,000 shares (split adjusted) subject to time vesting (Restricted Shares) and 122,000 shares (split adjusted) subject to performance based vesting (Performance Shares).

The Restricted Shares will cliff vest on the third annual anniversary of the grant date. The Performance Shares are set up to cliff vest on the third annual anniversary of the date that the performance goal is met. As of September 30, 2013, the performance goal was met when the Company averaged $0.3125 diluted earnings per share (split adjusted) for the past four consecutive quarters or total diluted earnings per share of $1.25 (split adjusted) during the same period. In accordance with the vesting terms of the Performance Shares agreements, the issued shares are due to fully vest on September 30, 2016.

On January 18, 2013, 18,000 shares (split adjusted) of restricted common stock were issued to each non-employee member of our Board of Directors and 4,000 shares (split adjusted) of restricted common stock to a regional president of our bank subsidiary for a total issuance of 22,000 shares (split adjusted) of restricted common stock. The restricted stock issued will vest equally each year over three years beginning on the first anniversary of the issuance.

Table of Contents

On June 4, 2013, 12,966 shares (split adjusted) of restricted common stock were issued to a regional president of our bank subsidiary. Of these issued shares, 9,666 shares (split adjusted) will vest equally each year over three years beginning on the first anniversary of the issuance. The remaining 3,000 shares (split adjusted) are subject to the previously discussed performance-based vesting.

The Company did not utilize a portion of its previously approved stock repurchase program during 2013. This program authorized the repurchase of 2,376,000 shares (split adjusted) of the Company s common stock. Shares repurchased to date under the program total 1,510,896 shares (split adjusted). The remaining balance available for repurchase is 865,104 shares (split adjusted) at September 30, 2013.

15. Non-Interest Expense

The table below shows the components of non-interest expense for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(In thousands)			
Salaries and employee benefits	$ 12,981	$ 11,652	$ 38,890	$ 34,941
Occupancy and equipment	4,010	3,805	11,498	10,788
Data processing expense	1,114	1,137	3,855	3,599
Other operating expenses:				
Advertising	363	534	1,176	1,898
Merger and acquisition expenses	1,034	296	1,063	1,988
Amortization of intangibles	802	694	2,406	2,018
Electronic banking expense	926	809	2,749	2,330
Directors fees	188	206	588	611
Due from bank service charges	136	137	437	412
FDIC and state assessment	684	588	1,991	1,742
Insurance	572	448	1,693	1,273
Legal and accounting	227	231	943	840
Other professional fees	404	411	1,367	1,263
Operating supplies	309	280	984	835
Postage	212	219	650	680
Telephone	291	270	885	792
Other expense	2,462	2,264	7,258	6,781
Total other operating expenses	8,610	7,387	24,190	23,463
Total non-interest expense	$ 26,715	$ 23,981	$ 78,433	$ 72,791

16. Concentration of Credit Risks

The Company s primary market areas are in Central Arkansas, North Central Arkansas, Southern Arkansas, Central Florida, Southwest Florida, the Florida Panhandle, the Florida Keys (Monroe County) and South Alabama. The Company primarily grants loans to customers located within these geographical areas unless the borrower has an established relationship with the Company.

The diversity of the Company s economic base tends to provide a stable lending environment. Although the Company has a loan portfolio that is diversified in both industry and geographic area, a substantial portion of its debtors ability to honor their contracts is dependent upon real estate values, tourism demand and the economic conditions prevailing in its market areas.

Table of Contents

17. Significant Estimates and Concentrations

Accounting principles generally accepted in the United States of America require disclosure of certain significant estimates and current vulnerabilities due to certain concentrations. Estimates related to the allowance for loan losses and certain concentrations of credit risk are reflected in Note 6, while deposit concentrations are reflected in Note 9.

Although the Company has a diversified loan portfolio, at September 30, 2013 and December 31, 2012, non-covered commercial real estate loans represented 57.7% and 56.0% of non-covered loans and 251.9% and 253.4% of total stockholders equity, respectively. Non-covered residential real estate loans represented 27.2% and 29.1% of non-covered loans and 118.8% and 131.7% of total stockholders equity at September 30, 2013 and December 31, 2012, respectively.

The current economic environment presents financial institutions with unprecedented circumstances and challenges which in some cases have resulted in large declines in the fair values of investments and other assets, constraints on liquidity and significant credit quality problems, including severe volatility in the valuation of real estate and other collateral supporting loans. The financial statements have been prepared using values and information currently available to the Company.

Given the volatility of current economic conditions, the values of assets and liabilities recorded in the financial statements could change rapidly, resulting in material future adjustments in asset values, the allowance for loan losses and capital that could negatively impact the Company s ability to meet regulatory capital requirements and maintain sufficient liquidity.

18. Commitments and Contingencies

In the ordinary course of business, the Company makes various commitments and incurs certain contingent liabilities to fulfill the financing needs of its customers. These commitments and contingent liabilities include lines of credit and commitments to extend credit and issue standby letters of credit. The Company applies the same credit policies and standards as it does in the lending process when making these commitments. The collateral obtained is based on the assessed creditworthiness of the borrower.

At September 30, 2013 and December 31, 2012, commitments to extend credit of $422.1 million and $407.1 million, respectively, were outstanding. A percentage of these balances are participated out to other banks; therefore, the Company can call on the participating banks to fund future draws. Since some of these commitments are expected to expire without being drawn upon, the total commitment amount does not necessarily represent future cash requirements.

Outstanding standby letters of credit are contingent commitments issued by the Company, generally to guarantee the performance of a customer in third-party borrowing arrangements. The term of the guarantee is dependent upon the credit worthiness of the borrower some of which are long-term. The amount of collateral obtained, if deemed necessary, is based on management s credit evaluation of the counterparty. Collateral held varies but may include accounts receivable, inventory, property, plant and equipment, commercial real estate and residential real estate. Management uses the same credit policies in granting lines of credit as it does for on-balance-sheet instruments. The maximum amount of future payments the Company could be required to make under these guarantees at September 30, 2013 and December 31, 2012, is $17.3 million and $16.4 million, respectively.

The Company and/or its subsidiary bank have various unrelated legal proceedings, most of which involve loan foreclosure activity pending, which, in the aggregate, are not expected to have a material adverse effect on the financial position and results of operations of the Company.

Table of Contents

19. Regulatory Matters

The Bank is subject to a legal limitation on dividends that can be paid to the parent company without prior approval of the applicable regulatory agencies. Arkansas bank regulators have specified that the maximum dividend limit state banks may pay to the parent company without prior approval is 75% of the current year earnings plus 75% of the retained net earnings of the preceding year. Since the Bank is also under supervision of the Federal Reserve, it is further limited if the total of all dividends declared in any calendar year by the Bank exceeds the Bank s net profits to date for that year combined with its retained net profits for the preceding two years. During the first nine months of 2013, the Company requested approximately $41.2 million in dividends from its banking subsidiary. This dividend is equal to approximately 75% of the current year earnings December 2012 through August 2013 from its banking subsidiary.

During October 2013, the Company requested a previously regulatory approved $50.0 million special dividend from the Bank in order to pay off the Small Business Lending Fund (SBLF) preferred stock acquired from Liberty Bancshares, Inc. during October 2013. Should the Company need to request additional dividends from the Bank during the remainder of 2013; regulatory approval will be required to do so.

The Federal Reserve Board s risk-based capital guidelines include the definitions for (1) a well-capitalized institution, (2) an adequately-capitalized institution, and (3) and undercapitalized institution. The criteria for a well-capitalized institution are: a 5% Tier 1 leverage capital ratio, a 6% Tier 1 risk-based capital ratio, and a 10% total risk-based capital ratio. As of September 30, 2013, the Bank met the capital standards for a well-capitalized institution. The Company s Tier 1 leverage capital ratio, Tier 1 risk-based capital ratio, and total risk-based capital ratio were 11.5%, 14.2%, and 15.4%, respectively, as of September 30, 2013.

20. Additional Cash Flow Information

The following is summary of the Company s additional cash flow information during the nine-month periods ended:

	Nine Months Ended September 30, 2013	2012
	(in thousands)	
Interest paid	$ 10,337	$ 18,371
Income taxes paid	16,875	23,070
Assets acquired by foreclosure	12,522	20,082

21. Financial Instruments

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements must maximize the use of observable inputs and minimize the use of unobservable inputs. There is a hierarchy of three levels of inputs that may be used to measure fair value:

Level 1 Quoted prices in active markets for identical assets or liabilities

Level 2 Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities

Level 3 Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities

Available-for-sale securities are the only material instruments valued on a recurring basis which are held by the Company at fair value. The Company does not have any Level 1 securities. Primarily all of the Company s securities are considered to be Level 2 securities. These Level 2 securities consist primarily of U.S. government-sponsored enterprises, mortgage-backed securities plus state and political subdivisions. For these securities, the Company obtains fair value measurements from an independent pricing service. The fair value measurements

38

consider observable data that may include dealer quotes, market spreads, cash flows, the U.S. Treasury yield curve, live trading levels, trade execution data, market consensus prepayment speeds, credit information and the bond s terms and conditions, among other things. As of September 30, 2013 and December 31, 2012, Level 3 securities were immaterial. In addition, there were no material transfers between hierarchy levels during 2013 and 2012.

The Corporation reviews the prices supplied by the independent pricing service, as well as their underlying pricing methodologies, for reasonableness and to ensure such prices are aligned with traditional pricing matrices. In general, the Company does not purchase investment portfolio securities with complicated structures. Pricing for the Company s investment securities is fairly generic and is easily obtained.

Impaired loans that are collateral dependent are the only material financial assets valued on a non-recurring basis which are held by the Company at fair value. Loan impairment is reported when full payment under the loan terms is not expected. Impaired loans are carried at the net realizable value of the collateral if the loan is collateral dependent. A portion of the allowance for loan losses is allocated to impaired loans if the value of such loans is deemed to be less than the unpaid balance. If these allocations cause the allowance for loan losses to require an increase, such increase is reported as a component of the provision for loan losses. The fair value of loans with specific allocated losses was $76.3 million and $97.8 million as of September 30, 2013 and December 31, 2012, respectively. This valuation is considered Level 3, consisting of appraisals of underlying collateral. The Company reversed approximately $147,000 and $101,000 of accrued interest receivable when non-covered impaired loans were put on non-accrual status during the three months ended September 30, 2013 and 2012, respectively. The Company reversed approximately $453,000 and $222,000 of accrued interest receivable when non-covered impaired loans were put on non-accrual status during the nine months ended September 30, 2013 and 2012, respectively.

Foreclosed assets held for sale are the only material non-financial assets valued on a non-recurring basis which are held by the Company at fair value, less estimated costs to sell. At foreclosure, if the fair value, less estimated costs to sell, of the real estate acquired is less than the Company s recorded investment in the related loan, a write-down is recognized through a charge to the allowance for loan losses. Additionally, valuations are periodically performed by management and any subsequent reduction in value is recognized by a charge to income. The fair value of foreclosed assets held for sale is estimated using Level 3 inputs based on appraisals of underlying collateral. As of September 30, 2013 and December 31, 2012, the fair value of foreclosed assets held for sale not covered by loss share, less estimated costs to sell was $14.2 million and $20.4 million, respectively.

The significant unobservable (Level 3) inputs used in the fair value measurement of collateral for collateral-dependent impaired loans and foreclosed assets primarily relate to customized discounting criteria applied to the customer s reported amount of collateral. The amount of the collateral discount depends upon the condition and marketability of the underlying collateral. As the Company s primary objective in the event of default would be to monetize the collateral to settle the outstanding balance of the loan, less marketable collateral would receive a larger discount. During the reported periods, collateral discounts ranged from 20% to 50% for commercial and residential real estate collateral.

Fair Values of Financial Instruments

The following methods and assumptions were used by the Company in estimating fair values of financial instruments as disclosed in these notes:

Cash and cash equivalents and federal funds sold For these short-term instruments, the carrying amount is a reasonable estimate of fair value.

Investment securities held-to-maturity These securities consist primarily of U.S. government-sponsored enterprises, mortgage-backed securities plus state and political subdivisions. For these securities, the Company obtains fair value measurements from an independent pricing service. The fair value measurements consider observable data that may include dealer quotes, market spreads, cash flows, the U.S. Treasury yield curve, live trading levels, trade execution data, market consensus prepayment speeds, credit information and the bond s terms and conditions, among other things.

Loans receivable not covered by loss share, net of non-covered impaired loans and allowance For variable-rate loans that reprice frequently and with no significant change in credit risk, fair values are assumed to approximate the carrying amounts. The fair values for fixed-rate loans are estimated using discounted cash flow analysis, based on interest rates currently being offered for loans with similar terms to borrowers of similar credit quality. Loan fair value estimates include judgments regarding future expected loss experience and risk characteristics.

Loans receivable covered by FDIC loss share, net of allowance Fair values for loans are based on a discounted cash flow methodology that considered factors including the type of loan and related collateral, classification status, fixed or variable interest rate, term of loan, whether or not the loan was amortizing and current discount rates. Loans were grouped together according to similar characteristics and were treated in the aggregate when applying various valuation techniques. The discount rates used for loans are based on current market rates for new originations of comparable loans and include adjustments for liquidity concerns. The discount rate does not include a factor for credit losses as that has been included in the estimated cash flows.

FDIC indemnification asset Although this asset is a contractual receivable from the FDIC, there is no effective interest rate. The Bank will collect this asset over the next several years. The amount ultimately collected will depend on the timing and amount of collections and charge-offs on the acquired assets covered by the loss sharing agreement. While this asset was recorded at its estimated fair value at acquisition date, it is not practicable to complete a fair value analysis on a quarterly or annual basis. This would involve preparing a fair value analysis of the entire portfolio of loans and foreclosed assets covered by the loss sharing agreement on a quarterly or annual basis in order to estimate the fair value of the FDIC indemnification asset.

Accrued interest receivable The carrying amount of accrued interest receivable approximates its fair value.

Deposits and securities sold under agreements to repurchase The fair values of demand, savings deposits and securities sold under agreements to repurchase are, by definition, equal to the amount payable on demand and therefore approximate their carrying amounts. The fair values for time deposits are estimated using a discounted cash flow calculation that utilizes interest rates currently being offered on time deposits with similar contractual maturities.

FHLB borrowed funds For short-term instruments, the carrying amount is a reasonable estimate of fair value. The fair value of long-term debt is estimated based on the current rates available to the Company for debt with similar terms and remaining maturities.

Accrued interest payable The carrying amount of accrued interest payable approximates its fair value.

Subordinated debentures The fair value of subordinated debentures is estimated using the rates that would be charged for subordinated debentures of similar remaining maturities.

Commitments to extend credit, letters of credit and lines of credit The fair value of commitments is estimated using the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements and the present creditworthiness of the counterparties. For fixed rate loan commitments, fair value also considers the difference between current levels of interest rates and the committed rates. The fair values of letters of credit and lines of credit are based on fees currently charged for similar agreements or on the estimated cost to terminate or otherwise settle the obligations with the counterparties at the reporting date. The fair value of these commitments is not material.

The following table presents the estimated fair values of the Company s financial instruments. The fair values of certain of these instruments were calculated by discounting expected cash flows, which involves significant judgments by management and uncertainties. Fair value is the estimated amount at which financial assets or liabilities could be exchanged in a current transaction between willing parties other than in a forced or liquidation sale. Because no market exists for certain of these financial instruments and because management does not intend to sell these financial instruments, the Company does not know whether the fair values shown below represent values at which the respective financial instruments could be sold individually or in the aggregate.

Table of Contents

	September 30, 2013		
	Carrying Amount	Fair Value	Level
	(In thousands)		
Financial assets:			
Cash and cash equivalents	$ 112,341	$ 112,341	1
Federal funds sold	10,700	10,700	1
Investment securities held-to-maturity	9,528	9,631	2
Loans receivable not covered by loss share, net of non-covered impaired loans and allowance	2,264,874	2,240,775	3
Loans receivable covered by FDIC loss share	306,966	306,966	3
FDIC indemnification asset	101,192	101,192	3
Accrued interest receivable	14,275	14,275	1
Financial liabilities:			
Deposits:			
Demand and non-interest bearing	$ 757,328	$ 757,328	1
Savings and interest-bearing transaction accounts	1,683,010	1,683,010	1
Time deposits	808,480	807,119	3
Federal funds purchased			N/A
Securities sold under agreements to repurchase	71,307	71,307	1
FHLB borrowed funds	270,232	275,602	2
Accrued interest payable	775	775	1
Subordinated debentures	3,093	3,100	3

	December 31, 2012		
	Carrying Amount	Fair Value	Level
	(In thousands)		
Financial assets:			
Cash and cash equivalents	$ 231,855	$ 231,855	1
Federal funds sold	17,148	17,148	1
Loans receivable not covered by loss share, net of non-covered impaired loans and allowance	2,188,253	2,202,859	3
Loans receivable covered by FDIC loss share	379,422	379,422	3
FDIC indemnification asset	139,646	139,646	3
Accrued interest receivable	16,305	16,305	1
Financial liabilities:			
Deposits:			
Demand and non-interest bearing	$ 666,414	$ 666,414	1
Savings and interest-bearing transaction accounts	1,784,047	1,784,047	1
Time deposits	1,032,991	1,037,235	3
Federal funds purchased			N/A
Securities sold under agreements to repurchase	66,278	66,278	1
FHLB borrowed funds	130,388	139,654	2
Accrued interest payable	1,243	1,243	1
Subordinated debentures	28,867	28,911	3

Table of Contents

22. Recent Accounting Pronouncements

In October 2012, the FASB issued an update, ASU 2012-06, *Business Combinations (Topic 805): Subsequent Accounting for an Indemnification Asset Recognized at the Acquisition Date as a Result of a Government-Assisted Acquisition of a Financial Institution*, to address the diversity in treatment with respect to indemnification assets recognized in connection with a government-assisted acquisition of a financial institution and the related asset subject to indemnification. When a reporting entity recognizes an indemnification asset as a result of a government-assisted acquisition of a financial institution, a change in the cash flows expected to be collected on the indemnified asset will result in a change in the value of such asset and should also result in a change in the respective indemnification asset. The update clarifies that the reporting entity should subsequently account for the change in the measurement of the indemnification asset on the same basis as the change in the assets subject to indemnification. Any amortization of changes in value should be limited to the contractual term of the indemnification agreement, which is the lesser of the term of the indemnification agreement or the remaining life of the indemnified assets. The new authoritative guidance became effective for reporting periods after January 1, 2013. ASU 2012-06 did not impact or change the impairment tests or results for the first nine months of 2013; the Company was already following the guidance provided for in this new standard.

In February 2013, the FASB issued an update, ASU 2013-02, *Comprehensive Income (Topic 220): Reporting Items Reclassified Out of Accumulated Other Comprehensive Income*, which requires disclosure of amounts reclassified out of accumulated other comprehensive income in their entirety, by component, on the face of the statement of comprehensive income or in the notes to the financial statements. Amounts that are not required to be classified in their entirety to net income must be cross-referenced to other disclosures that provide additional detail. ASU 2013-02 is effective prospectively for fiscal years and interim periods beginning after January 1, 2013, and did not have an impact on the Company s financial position or results of operations.

Presently, the Company is not aware of any changes from the Financial Accounting Standards Board that will have a material impact on the Company s present or future financial statements.

23. Subsequent Events

Business Combination Subsequent to September 30, 2013, on the morning of October 24, 2013, Home BancShares, Inc. (Home), parent company of Centennial Bank (Centennial), completed its acquisition of Liberty Bancshares, Inc. (Liberty), parent company of Liberty Bank of Arkansas (Liberty Bank), pursuant to a previously announced definitive agreement and plan of merger whereby a wholly-owned acquisition subsidiary (Acquisition Sub) of Home merged with and into Liberty, resulting in Liberty becoming a wholly-owned subsidiary of Home. Immediately thereafter, Liberty Bank was merged into Centennial. Under the terms of the Agreement and Plan of Merger dated June 25, 2013 by and among Home, Centennial, Liberty, Liberty Bank and Acquisition Sub (the Merger Agreement), Home will issue 8,763,930 shares of its common stock valued at approximately $290.1 million as of October 23, 2013, plus $30.0 million in cash in exchange for all outstanding shares of Liberty common stock. As expected, Home also repurchased all of Liberty s SBLF preferred stock held by the U.S. Treasury shortly after the closing.

The combined company now has approximately $7.0 billion in total assets, $5.4 billion in deposits, $4.4 billion in loans, 153 branches, 186 ATMs, and 1,500 employees across Arkansas, Florida and Southern Alabama. The merger will significantly increase the Company s deposit market share in Arkansas making it the 2nd largest bank holding company headquartered in Arkansas.

The transaction is accretive to the Company s book value per common share and tangible book value per common share. On a pro forma basis as of September 30, 2013, the projected book value and tangible book value per common share are $12.84 and $8.04, respectively. Additionally the Leverage ratio, Tier 1 risk-based capital, Total risk-based capital and Tangible common equity ratio are projected to be 8.3%, 10.5%, 11.2% and 7.9%, respectively as of September 30, 2013 on a pro forma basis.

Table of Contents

The following unaudited pro forma combined consolidated financial information is the preliminary determination of fair values of LBI s assets acquired and liabilities assumed as of the acquisition date. This information is subject to adjustment and may vary from the actual fair values assigned that will be recorded upon completion of the final fair value analysis. Currently, HBI is working to finalize its determination of the fair values of the acquired assets and assumed liabilities which could significantly change both the amount and the composition of these estimated purchase accounting adjustments.

	Liberty Bank		
	Acquired from Liberty	Fair Value Adjustments	As Recorded by HBI
	(Dollars in thousands)		
Assets			
Cash and due from banks	$ 26,101	$ (30,000)	$ (3,899)
Interest-bearing deposits with other banks	4,270	(52,500)	(48,230)
Federal funds sold	4,600		4,600
Investment securities	731,249	(9,598)	721,651
Loans not covered by loss share	1,835,644	(96,060)	1,739,584
Allowance for loan losses	(21,964)	21,964	
Total loans receivable	1,813,680	(74,096)	1,739,584
Bank premises and equipment, net	82,879		82,879
Foreclosed assets held for sale not covered by loss share	34,795	(9,596)	25,199
Cash value of life insurance	3,669		3,669
Accrued interest receivable	10,455		10,455
Deferred tax asset	15,687	40,119	55,806
Goodwill	88,499	116,843	205,342
Core deposit intangibles	1,488	11,521	13,009
Other assets	5,487		5,487
Total assets acquired	$ 2,822,859	$ (7,307)	$ 2,815,552
Liabilities			
Deposits			
Demand and non-interest-bearing	$ 233,943	$	$ 233,943
Savings and interest-bearing transaction accounts	1,017,805		1,017,805
Time deposits	881,666	(1,383)	880,283
Total deposits	2,133,414	(1,383)	2,132,031
Securities sold under agreements to repurchase	83,376		83,376
FHLB borrowed funds	226,203	4,392	230,595
Accrued interest payable and other liabilities	4,231	17,500	21,731
Subordinated debentures	57,733		57,733
Total liabilities assumed	2,504,957	20,509	2,525,466

Equity			
Preferred stock	52,500	(52,500)	
Common stock	12	76	88
Capital surplus	167,089	122,909	289,998
Retained earnings	110,995	(110,995)	
Accumulated other comprehensive income	(4,340)	4,340	
Less: Treasury stock	(8,354)	8,354	
Total equity assumed	317,902	(27,816)	290,086
Total liabilities and equity assumed	$ 2,822,859	$ (7,307)	$ 2,815,552

43

Table of Contents

Certain fair value measurements have not been completed, and the purchase price allocation remains preliminary due to the timing of the acquisition and due to the number of assets acquired and liabilities assumed. We will continue to review the estimated fair values of property and equipment, intangible assets, and other assets and liabilities, and to evaluate the assumed tax positions and contingencies.

The unaudited pro forma combined consolidated financial information presents how the combined financial information of HBI and LBI might have appeared had the businesses actually been combined. The following schedule represents the unaudited pro forma combined financial information as of the three and nine-month periods ended September 30, 2013 and 2012, assuming the acquisition was completed as of January 1, 2013 and 2012, respectively:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2013	**2012**	**2013**	**2012**
	(In thousands, except per share data)			
Total interest income	$ 75,215	$ 71,741	$ 223,620	$ 216,649
Total non-interest income	16,352	17,483	49,676	49,652
Net income available to all shareholders	23,984	22,521	70,472	62,733
Basic earnings per common share	$ 0.37	$ 0.35	$ 1.08	$ 0.96
Diluted earnings per common share	0.37	0.34	1.08	0.96

The unaudited pro forma consolidated financial information is presented for illustrative purposes only and does not indicate the financial results of the combined company had the companies actually been combined at the beginning of the period presented and had the impact of possible revenue enhancements and expense efficiencies, among other factors, been considered and, accordingly, does not attempt to predict or suggest future results. It also does not necessarily reflect what the historical results of the combined company would have been had the companies been combined during this period.

44

Table of Contents

Report of Independent Registered Public Accounting Firm

Audit Committee, Board of Directors and Stockholders

Home BancShares, Inc.

Conway, Arkansas

We have reviewed the accompanying condensed consolidated balance sheet of Home BancShares, Inc. (the Company) as of September 30, 2013, and the related condensed consolidated statements of income and comprehensive income for the three-month and nine-month periods ended September 30, 2013 and 2012, and condensed consolidated statements of stockholders equity and cash flows for the nine-month periods ended September 30, 2013 and 2012. These interim financial statements are the responsibility of the Company s management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures to financial data and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2012, and the related consolidated statements of income, comprehensive income, stockholders equity and cash flows for the year then ended (not presented herein); and in our report dated March 4, 2013, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2012, is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ **BKD, LLP**

Little Rock, Arkansas

November 7, 2013

Table of Contents

Item 2: MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read in conjunction with our Form 10-K, filed with the Securities and Exchange Commission on March 4, 2013, which includes the audited financial statements for the year ended December 31, 2012. *Unless the context requires otherwise, the terms Company , us , we , and our refer to Home BancShares, Inc. on a consolidated basis.*

General

We are a bank holding company headquartered in Conway, Arkansas, offering a broad array of financial services through our wholly owned bank subsidiary, Centennial Bank. As of September 30, 2013, we had, on a consolidated basis, total assets of $4.16 billion, loans receivable, net of $2.65 billion, total deposits of $3.25 billion, and stockholders equity of $545.1 million.

We generate most of our revenue from interest on loans and investments, service charges, and mortgage banking income. Deposits and FHLB borrowed funds are our primary sources of funding. Our largest expenses are interest on our funding sources and salaries and related employee benefits. We measure our performance by calculating our return on average common equity, return on average assets, and net interest margin. We also measure our performance by our efficiency ratio, which is calculated by dividing non-interest expense less amortization of core deposit intangibles by the sum of net interest income on a tax equivalent basis and non-interest income.

Key Financial Measures

	As of or for the Three Months Ended September 30,		As of or for the Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in thousands, except per share data[2])			
Total assets	$ 4,161,306	$ 3,887,909	$ 4,161,306	$ 3,887,909
Loans receivable not covered by loss share	2,378,838	2,076,248	2,378,838	2,076,248
Loans receivable covered by FDIC loss share	308,072	407,416	308,072	407,416
Allowance for loan losses	38,748	54,440	38,748	54,440
FDIC claims receivable	31,168	24,580	31,168	24,580
Total deposits	3,248,818	3,132,469	3,248,818	3,132,469
Total stockholders equity	545,142	509,978	545,142	509,978
Net income	18,363	16,095	53,570	46,083
Basic earnings per common share	0.33	0.29	0.96	0.82
Diluted earnings per common share	0.33	0.28	0.95	0.81
Diluted earnings per common share excluding intangible amortization [1]	0.33	0.29	0.97	0.83
Annualized net interest margin FTE	5.41%	4.65%	5.25%	4.65%
Efficiency ratio	45.67	46.24	45.56	47.35

Annualized return on average assets	1.80	1.61	1.73	1.56
Annualized return on average common equity	13.63	12.78	13.53	12.60

(1) See Table 17 Diluted Earnings Per Common Share Excluding Intangible Amortization for a reconciliation to GAAP for diluted earnings per common share excluding intangible amortization.
(2) All per share amounts have been restated to reflect the effect of the 2-for-1 stock split during June 2013.

46

Table of Contents

Overview

Results of Operations for Three Months Ended September 30, 2013 and 2012

Our net income increased $2.3 million or 14.1% to $18.4 million for the three-month period ended September 30, 2013, from $16.1 million for the same period in 2012. On a diluted earnings per common share basis, our earnings were $0.33 and $0.28 (split adjusted) for the three-month periods ended September 30, 2013 and 2012, respectively. The $2.3 million increase in net income is primarily associated with the additional net interest income and other non-interest income resulting from our 2012 acquisitions of Heritage and Premier. Furthermore, there was $1.2 million of additional gains from the sale of SBA loans, premises & equipment and OREO plus supplemental other income of $271,000 from the recovery of a prior year loss. There was also a reduction in the provision for loan losses of $167,000 in third quarter of 2013 when compared to the third quarter of 2012. These improvements were partially offset by a modest increase in the costs associated with the asset growth from our acquisitions and approximately $738,000 of additional merger expenses.

During the third quarter of 2013, one pool of our covered loans sharing common risk characteristics paid off in its entirety. As a result of this payoff we collected $1.9 million of unexpected cash flows. This unexpected positive cash flow resulted in the recognition of $1.9 million as an extra adjustment to yield on loans for the third quarter of 2013. This positive event reduced the indemnification asset by approximately $1.5 million of which the entire amount was recognized as a reduction of earnings for the third quarter of 2013, and increased our FDIC true-up liability by $170,000 of which the entire amount was recognized as expense for the third quarter of 2013. The combined effect of this payoff on pre-tax net income was $210,000 for the third quarter of 2013.

During the first quarter of 2013 impairment testing on the estimated cash flows of covered loans, five loan pools were determined to have a materially projected credit improvement. As a result of this improvement, the Company will recognize approximately $15.6 million as an adjustment to yield over the weighted average life of the loans with $1.9 million of this amount being recognized during the third quarter of 2013. Improvements in credit quality decrease the basis in the related indemnification asset and increase our FDIC true up liability. This positive event will reduce the indemnification asset by approximately $12.5 million of which $1.8 million was recognized for the third quarter of 2013, and increase our FDIC true-up liability by $1.6 million of which $57,000 was recognized for the third quarter of 2013. The $12.5 million will be amortized over the weighted average life of the shared-loss agreements. This amortization will be shown as a reduction to FDIC indemnification non-interest income. The $1.6 million will be expensed over the remaining true-up measurement date as other non-interest expense.

Our annualized net interest margin, on a fully taxable equivalent basis, was 5.41% for the three months ended September 30, 2013, compared to 4.65% for the same period in 2012. Our ability to improve pricing on interest bearing deposits combined with additional yield on FDIC loss sharing loans which more than offset the lower interest rates on newly originated loans in the loan portfolio during this historically low rate environment allowed the Company to expand net interest margin. Our acquisitions have helped improve the yield on the loan portfolio. For the three months ended September 30, 2013, the effective yield on non-covered loans and covered loans was 5.88% and 12.76%, respectively. Excluding the $3.8 million of additional yield noted above for the third quarter, the pro forma effective yield on covered loans was 7.98%.

Our annualized return on average assets was 1.80% for the three months ended September 30, 2013, compared to 1.61% for the same period in 2012. Our annualized return on average common equity was 13.63% for the three months ended September 30, 2013, compared to 12.78% for the same period in 2012, respectively. The improvements in our ratios from 2012 to 2013 are consistent with the previously discussed changes in earnings for the three months ended September 30, 2013, compared to the same period in 2012.

Our efficiency ratio was 45.67% for the three months ended September 30, 2013, compared to 46.24% for the same period in 2012. The improvement in the efficiency ratio is primarily associated with additional net interest income and other non-interest income resulting from our 2012 acquisitions of Heritage and Premier combined with additional gains and recoveries offset by a modest increase in costs associated with the asset growth from our acquisitions and additional merger expenses.

47

Table of Contents

Results of Operations for Nine Months Ended September 30, 2013 and 2012

Our net income increased $7.5 million or 16.2% to $53.6 million for the nine-month period ended September 30, 2013, from $46.1 million for the same period in 2012. On a diluted earnings per common share basis, our earnings were $0.95 and $0.81 (split adjusted) for the nine-month periods ended September 30, 2013 and 2012, respectively. The $7.5 million increase in net income is primarily associated with the additional net interest income and other non-interest income resulting from our 2012 acquisitions of Vision, Heritage and Premier and a reduction in merger expenses by $925,000. Furthermore, there was $1.7 million of additional gains from the sale of SBA loans, premises & equipment, OREO and securities plus supplementary other income of $271,000 from the recovery of a prior year loss. There was also a reduction in the provision for loan losses of $650,000 in the first nine months of 2013 when compared to the first nine months 2012. These improvements were partially offset by a modest increase in the costs associated with the asset growth from our acquisitions.

During the third quarter of 2013, one pool of our covered loans sharing common risk characteristics paid off in its entirety. As a result of this payoff we collected $1.9 million of unexpected cash flows. This unexpected positive cash flow resulted in the recognition of $1.9 million as an extra adjustment to yield on loans for the third quarter of 2013. This positive event reduced the indemnification asset by approximately $1.5 million of which the entire amount was recognized as a reduction of earnings for the third quarter of 2013, and increased our FDIC true-up liability by $170,000 of which the entire amount was recognized as expense for the third quarter of 2013. The combined effect of this payoff on pre-tax net income was $210,000 for the third quarter of 2013.

As discussed in the preceding section, impairment testing on the estimated cash flows of the covered loans during the first quarter of 2013 were determined to have a materially projected credit improvement. As a result of this impairment testing, the Company recognized $6.1 million as an adjustment to yield over the weighted average life of the loans during the first nine months of 2013. Conversely, the indemnification asset was amortized by approximately $5.9 million and the FDIC true-up expense was increased by approximately $171,000 during the first nine months of 2013, respectively.

Our annualized net interest margin, on a fully taxable equivalent basis, was 5.25% for the nine months ended September 30, 2013, compared to 4.65% for the same period in 2012. Our ability to improve pricing on interest bearing deposits combined with additional yield on FDIC loss sharing loans which more than offset the lower interest rates on newly originated loans in the loan portfolio during this historically low rate environment allowed the Company to expand net interest margin. Our acquisitions have helped improve the yield on the loan portfolio. For the nine months ended September 30, 2013, the effective yield on non-covered loans and covered loans was 6.01% and 11.23%, respectively. Excluding the $8.0 million of additional yield noted above for 2013, the pro forma effective yield on covered loans was 8.13%.

Our annualized return on average assets was 1.73% for the nine months ended September 30, 2013, compared to 1.56% for the same period in 2012. Our annualized return on average common equity was 13.53% for the nine months ended September 30, 2013, compared to 12.60% for the same period in 2012, respectively. The improvements in our ratios from 2012 to 2013 are consistent with the previously discussed changes in earnings for the nine months ended September 30, 2013, compared to the same period in 2012.

Our efficiency ratio was 45.56% for the nine months ended September 30, 2013, compared to 47.35% for the same period in 2012. The improvement in the efficiency ratio is primarily associated with additional net interest income and other non-interest income resulting from our 2012 acquisitions of Vision, Heritage and Premier combined with additional gains, recoveries and lower merger expenses offset by a modest increase in costs associated with the asset growth from our acquisitions.

48

Table of Contents

Financial Condition as of and for the Period Ended September 30, 2013 and December 31, 2012

Our total assets as of September 30, 2013 decreased $80.8 million to $4.16 billion from the $4.24 billion reported as of December 31, 2012. Our loan portfolio not covered by loss share increased by $47.6 million to $2.38 billion as of September 30, 2013, from $2.33 billion as of December 31, 2012. Our loan portfolio covered by loss share decreased by $76.8 million to $308.1 million as of September 30, 2013, from $384.9 million as of December 31, 2012. The decrease in covered loans is primarily associated with pay-downs and payoffs in our covered loan portfolio. Stockholders equity increased $29.7 million to $545.1 million as of September 30, 2013, compared to $515.5 million as of December 31, 2012. The annualized improvement in stockholders equity for the first nine months of 2013 was 7.7%. The increase in stockholders equity is primarily associated with the $40.2 million of comprehensive income less the $12.1 million of dividends paid for 2013.

As of September 30, 2013, our non-performing non-covered loans increased to $28.4 million, or 1.2%, of total non-covered loans from $27.3 million, or 1.17%, of total non-covered loans as of December 31, 2012. The allowance for loan losses for non-covered loans as a percent of non-performing non-covered loans decreased to 132.38% as of September 30, 2013, compared to 165.62% as of December 31, 2012. Non-performing non-covered loans in Arkansas were $7.1 million at September 30, 2013 compared to $12.1 million as of December 31, 2012. Non-performing non-covered loans in Florida were $21.3 million at September 30, 2013 compared to $15.2 million as of December 31, 2012. Non-performing non-covered loans in Alabama were $8,000 at September 30, 2013. As of December 31, 2012, no loans in Alabama were non-performing.

As of September 30, 2013, our non-performing non-covered assets improved to $42.8 million, or 1.15%, of total non-covered assets from $47.8 million, or 1.30%, of total non-covered assets as of December 31, 2012. Non-performing non-covered assets in Arkansas were $17.2 million at September 30, 2013 compared to $24.6 million as of December 31, 2012. Non-performing non-covered assets in Florida were $25.5 million at September 30, 2013 compared to $23.2 million as of December 31, 2012. Non-performing non-covered assets in Alabama were $8,000 at September 30, 2013. As of December 31, 2012, no assets in Alabama were non-performing.

Critical Accounting Policies

Overview. We prepare our consolidated financial statements based on the selection of certain accounting policies, generally accepted accounting principles and customary practices in the banking industry. These policies, in certain areas, require us to make significant estimates and assumptions. Our accounting policies are described in detail in the notes to our consolidated financial statements in Note 1 of the audited consolidated financial statements included in our Form 10-K, filed with the Securities and Exchange Commission.

We consider a policy critical if (i) the accounting estimate requires assumptions about matters that are highly uncertain at the time of the accounting estimate; and (ii) different estimates that could reasonably have been used in the current period, or changes in the accounting estimate that are reasonably likely to occur from period to period, would have a material impact on our financial statements. Using these criteria, we believe that the accounting policies most critical to us are those associated with our lending practices, including the accounting for the allowance for loan losses, acquisition accounting for covered loans and related indemnification asset, investments, foreclosed assets held for sale, intangible assets, income taxes and stock options.

Investments Available-for-sale. Securities that are held as available-for-sale are reported at fair value with unrealized holding gains and losses reported as a separate component of stockholders equity and other comprehensive income (loss), net of taxes. Securities that are held as available-for-sale are used as a part of our asset/liability management strategy. Securities that may be sold in response to interest rate changes, changes in prepayment risk, the need to increase regulatory capital, and other similar factors are classified as available-for-sale.

Loans Receivable Not Covered by Loss Share and Allowance for Loan Losses. Except for loans acquired during our acquisitions, substantially all of our loans receivable not covered by loss share are reported at their outstanding principal balance adjusted for any charge-offs, as it is management s intent to hold them for the foreseeable future or until maturity or payoff, except for mortgage loans held for sale. Interest income on loans is accrued over the term of the loans based on the principal balance outstanding.

Table of Contents

The allowance for loan losses is established through a provision for loan losses charged against income. The allowance represents an amount that, in management s judgment, will be adequate to absorb probable credit losses on identifiable loans that may become uncollectible and probable credit losses inherent in the remainder of the loan portfolio. The amounts of provisions for loan losses are based on management s analysis and evaluation of the loan portfolio for identification of problem credits, internal and external factors that may affect collectability, relevant credit exposure, particular risks inherent in different kinds of lending, current collateral values and other relevant factors.

The allowance consists of allocated and general components. The allocated component relates to loans that are classified as impaired. For those loans that are classified as impaired, an allowance is established when the discounted cash flows, collateral value or observable market price of the impaired loan is lower than the carrying value of that loan. The general component covers non-classified loans and is based on historical charge-off experience and expected loss given default derived from the Bank s internal risk rating process. Other adjustments may be made to the allowance for pools of loans after an assessment of internal or external influences on credit quality that are not fully reflected in the historical loss or risk rating data.

Loans considered impaired, under FASB ASC 310-10-35, are loans for which, based on current information and events, it is probable that the Company will be unable to collect all amounts due according to the contractual terms of the loan agreement. The Company applies this policy even if delays or shortfalls in payment are expected to be insignificant. The aggregate amount of impairment of loans is utilized in evaluating the adequacy of the allowance for loan losses and amount of provisions thereto. Losses on impaired loans are charged against the allowance for loan losses when in the process of collection it appears likely that such losses will be realized. The accrual of interest on impaired loans is discontinued when, in management s opinion the collection of interest is doubtful, or generally when loans are 90 days or more past due. When accrual of interest is discontinued, all unpaid accrued interest is reversed. Interest income is subsequently recognized only to the extent cash payments are received in excess of principal due. Loans are returned to accrual status when all the principal and interest amounts contractually due are brought current and future payments are reasonably assured.

Groups of loans with similar risk characteristics are collectively evaluated for impairment based on the group s historical loss experience adjusted for changes in trends, conditions and other relevant factors that affect repayment of the loans.

Loans are placed on non-accrual status when management believes that the borrower s financial condition, after giving consideration to economic and business conditions and collection efforts, is such that collection of interest is doubtful, or generally when loans are 90 days or more past due. Loans are charged against the allowance for loan losses when management believes that the collectability of the principal is unlikely. Accrued interest related to non-accrual loans is generally charged against the allowance for loan losses when accrued in prior years and reversed from interest income if accrued in the current year. Interest income on non-accrual loans may be recognized to the extent cash payments are received, although the majority of payments received are usually applied to principal. Non-accrual loans are generally returned to accrual status when principal and interest payments are less than 90 days past due, the customer has made required payments for at least six months, and we reasonably expect to collect all principal and interest.

Acquisition Accounting, Acquired Loans and Related Indemnification Asset. The Company accounts for its acquisitions under ASC Topic 805, *Business Combinations*, which requires the use of the acquisition method of accounting. All identifiable assets acquired, including loans, are recorded at fair value. No allowance for loan losses related to the acquired loans is recorded on the acquisition date as the fair value of the loans acquired incorporates assumptions regarding credit risk. All loans acquired are recorded at fair value in accordance with the fair value methodology prescribed in ASC Topic 820. For covered acquired loans fair value is exclusive of the shared-loss agreements with the Federal Deposit Insurance Corporation (FDIC). The fair value estimates associated with the loans include estimates related to expected prepayments and the amount and timing of undiscounted expected principal, interest and other cash flows.

Table of Contents

Over the life of the purchased credit impaired loans acquired, the Company continues to estimate cash flows expected to be collected on pools of loans sharing common risk characteristics, which are treated in the aggregate when applying various valuation techniques. The Company evaluates at each balance sheet date whether the present value of its pools of loans determined using the effective interest rates has decreased and if so, recognizes a provision for loan loss in its consolidated statement of income. For any increases in cash flows expected to be collected, the Company adjusts the amount of accretable yield recognized on a prospective basis over the pool s remaining life.

Because the FDIC will reimburse the Company for certain acquired loans should the Company experience a loss, an indemnification asset is recorded at fair value at the acquisition date. The indemnification asset is recognized at the same time as the indemnified loans, and measured on the same basis, subject to collectability or contractual limitations. The shared-loss agreements on the acquisition date reflect the reimbursements expected to be received from the FDIC, using an appropriate discount rate, which reflects counterparty credit risk and other uncertainties.

For our FDIC-assisted transactions, shared-loss agreements continue to be measured on the same basis as the related indemnified loans. Because the acquired loans are subject to the accounting prescribed by ASC Topic 310, subsequent changes to the basis of the shared-loss agreements also follow that model. Deterioration in the credit quality of the loans (immediately recorded as an adjustment to the allowance for loan losses) would immediately increase the basis of the shared-loss agreements, with the offset recorded through the consolidated statement of income as a reduction of the provision for loan losses. Increases in the credit quality or cash flows of loans (reflected as an adjustment to yield and accreted into income over the weighted-average remaining life of the loans) decrease the basis of the shared-loss agreements, with such decrease being amortized into income over 1) the same period or 2) the life of the shared-loss agreements, whichever is shorter. Loss assumptions used in the basis of the indemnified loans are consistent with the loss assumptions used to measure the indemnification asset. Fair value accounting incorporates into the fair value of the indemnification asset an element of the time value of money, which is accreted back into income over the life of the shared-loss agreements.

Upon the determination of an incurred loss the indemnification asset will be reduced by the amount owed by the FDIC. A corresponding claim receivable is recorded until cash is received from the FDIC.

Foreclosed Assets Held for Sale. Real estate and personal properties acquired through or in lieu of loan foreclosure are to be sold and are initially recorded at fair value at the date of foreclosure, establishing a new cost basis. Valuations are periodically performed by management, and the real estate and personal properties are carried at fair value less cost to sell. Gains and losses from the sale of other real estate and personal properties are recorded in non-interest income, and expenses used to maintain the properties are included in non-interest expenses.

Intangible Assets. Intangible assets consist of goodwill and core deposit intangibles. Goodwill represents the excess purchase price over the fair value of net assets acquired in business acquisitions. The core deposit intangible represents the excess intangible value of acquired deposit customer relationships as determined by valuation specialists. The core deposit intangibles are being amortized over 48 to 114 months on a straight-line basis. Goodwill is not amortized but rather is evaluated for impairment on at least an annual basis. We perform an annual impairment test of goodwill and core deposit intangibles as required by FASB ASC 350, *Intangibles Goodwill and Other*, in the fourth quarter.

Income Taxes. The Company accounts for income taxes in accordance with income tax accounting guidance (ASC 740, *Income Taxes*). The income tax accounting guidance results in two components of income tax expense: current and deferred. Current income tax expense reflects taxes to be paid or refunded for the current period by applying the provisions of the enacted tax law to the taxable income or excess of deductions over revenues. The Company determines deferred income taxes using the liability (or balance sheet) method. Under this method, the net deferred tax asset or liability is based on the tax effects of the differences between the book and tax bases of assets and liabilities, and enacted changes in tax rates and laws are recognized in the period in which they occur.

Table of Contents

Deferred income tax expense results from changes in deferred tax assets and liabilities between periods. Deferred tax assets are recognized if it is more likely than not, based on the technical merits, that the tax position will be realized or sustained upon examination. The term more likely than not means a likelihood of more than 50 percent; the terms examined and upon examination also include resolution of the related appeals or litigation processes, if any. A tax position that meets the more-likely-than-not recognition threshold is initially and subsequently measured as the largest amount of tax benefit that has a greater than 50 percent likelihood of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. The determination of whether or not a tax position has met the more-likely-than-not recognition threshold considers the facts, circumstances and information available at the reporting date and is subject to the management s judgment. Deferred tax assets are reduced by a valuation allowance if, based on the weight of evidence available, it is more likely than not that some portion or all of a deferred tax asset will not be realized.

The Company and its subsidiary file consolidated tax returns. Its subsidiary provides for income taxes on a separate return basis, and remits to the Company amounts determined to be currently payable.

Stock Options. In accordance with FASB ASC 718, *Compensation Stock Compensation,* and FASB ASC 505-50, *Equity-Based Payments to Non-Employees*, the fair value of each option award is estimated on the date of grant. The Company recognizes compensation expense for the grant-date fair value of the option award over the vesting period of the award.

Acquisitions

Acquisition Vision Bank

On February 16, 2012, we acquired 17 branch locations in the Gulf Coast communities of Baldwin County, Alabama, and the Florida Panhandle through the acquisition of Vision Bank. Including the effects of purchase accounting adjustments, we acquired total assets of $529.5 million, total performing loans (after discount) of $340.3 million, cash and due from banks of $140.2 million, goodwill of $17.4 million, fixed assets of $12.5 million, deferred taxes of $11.2 million, core deposit intangible of $3.2 million and total deposits of $524.4 million. The fair value discount on the $355.8 million of gross loans was $15.5 million. We did not purchase certain of Vision s performing loans nor any of its non-performing loans or other real estate owned.

See Note 2 Business Combinations in the Notes to Consolidated Financial Statements for an additional discussion for the acquisition of Vision Bank.

Acquisition Heritage Bank of Florida

On November 2, 2012, Centennial Bank acquired all the deposits and substantially all the assets of Heritage Bank from the FDIC. This transaction did not include any non-performing loans or other real estate owned of Heritage. In connection with the Heritage acquisition, Centennial Bank opted to not enter into a loss-sharing agreement with the FDIC.

Heritage operated three banking offices located in Tampa, Lutz and Wesley Chapel, Florida. Including the effects of the purchase accounting adjustments, Centennial Bank acquired approximately $224.8 million in assets including a cash settlement of $82.3 million to balance the transaction, federal funds sold of $7.0 million, approximately $92.6 million in performing loans including loan discounts, core deposit intangible of $1.1 million and approximately $219.5 million of deposits.

See Note 2 Business Combinations in the Notes to Consolidated Financial Statements for an additional discussion for the acquisition of Heritage Bank.

Table of Contents

Acquisition Premier Bank

On December 1, 2012, Home BancShares, Inc. completed the acquisition of all of the issued and outstanding shares of common stock of Premier Bank, a Florida state-chartered bank with its principal office located in Tallahassee, Florida (Premier), pursuant to an Asset Purchase Agreement (the Premier Agreement) with Premier Bank Holding Company, a Florida corporation and bank holding company (PBHC), dated August 14, 2012. The Company has merged Premier with and into the Company s wholly-owned subsidiary, Centennial Bank, an Arkansas state-chartered bank. The Company paid a purchase price to PBHC of $1,415,000 for the Acquisition.

The Acquisition was conducted in accordance with the provisions of Section 363 of the Bankruptcy Code pursuant to a voluntary petition for relief under Chapter 11 of the Bankruptcy Code filed by PBHC with the Bankruptcy Court on August 14, 2012. The sale of Premier by PBHC was subject to certain bidding procedures approved by the Bankruptcy Court. No qualifying competing bids were received. The Bankruptcy Court entered a final order on November 29, 2012 approving the sale of Premier to the Company pursuant to and in accordance with the Premier Agreement.

Premier conducted banking business from six locations in the Florida panhandle cities of Tallahassee (five) and Quincy (one). Including the effects of the purchase accounting adjustments, Centennial Bank acquired approximately $264.8 million in assets, $12.5 million in investment securities, $4.0 million of federal funds sold, $138.1 million in loans including loan discounts, $5.1 million of bank premises and equipment, $7.6 million of foreclosed assets, $8.6 million of goodwill, $1.9 million of core deposit intangible, $5.7 million in cash value of life insurance, $246.3 million of deposits and $13.3 million of FHLB borrowed funds.

See Note 2 Business Combinations in the Notes to Consolidated Financial Statements for an additional discussion for the acquisition of Premier Bank.

FDIC Indemnification Asset

In conjunction with FDIC-assisted transactions, the Company entered into loss share agreements with the FDIC. These agreements cover realized losses on loans, foreclosed real estate and certain other assets. These loss share assets are measured separately from the loan portfolios because they are not contractually embedded in the loans and are not transferable with the loans should the Company choose to dispose of them. Fair values at the acquisition dates were estimated based on projected cash flows available for loss-share based on the credit adjustments estimated for each loan pool and the loss share percentages. The loss share assets are also separately measured from the related loans and foreclosed real estate and recorded as FDIC indemnification assets on the Consolidated Balance Sheets. Subsequent to the acquisition date, reimbursements received from the FDIC for actual incurred losses will reduce the loss share assets. Reductions to expected credit losses, to the extent such reductions to expected credit losses are the result of an improvement to the actual or expected cash flows from the covered assets, will also reduce the loss share assets. Increases in expected credit losses will require an increase to the allowance for loan losses and a corresponding increase to the loss share assets. As the loss share agreements approach the various expiration dates there could be unexpected volatility as future expected loan losses might become projected to occur outside of the loss share coverage reimbursement window.

Table of Contents

The following table summarizes the activity in the Company s FDIC indemnification asset during the periods indicated:

Changes in FDIC Indemnification Asset

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(Dollars in thousands)			
Beginning balance	$ 116,071	$ 162,439	$ 139,646	$ 193,856
Incurred claims for FDIC covered credit losses	(11,702)	(9,724)	(31,402)	(47,592)
FDIC indemnification accretion/(amortization)	(3,177)	373	(7,452)	1,492
Reduction in provision for loan losses:				
Benefit attributable to FDIC loss share agreements		670	400	6,002
Ending balance	$ 101,192	$ 153,758	$ 101,192	$ 153,758

FDIC-Assisted Acquisitions True Up

Our purchase and assumption agreements in connection with our FDIC-assisted acquisitions allow the FDIC to recover a portion of the loss share funds previously paid out under the indemnification agreements in the event losses fail to reach the expected loss under a claw back provision. Should the markets associated with any of the banks we acquired through FDIC-assisted transactions perform better than initially projected, the Bank is required to pay this clawback (or true-up) payment to the FDIC on a specified date following the tenth anniversary of such acquisition (the True-Up Measurement Date).

Specifically, in connection with the Old Southern and Key West acquisitions, such true-up payments would be equal to 50% of the excess, if any, of (i) 20% of a stated threshold of $110.0 million in the case of Old Southern and $23.0 million in the case of Key West, less (ii) the sum of (A) 25% of the asset premium (discount) plus (B) 25% of the Cumulative Shared Loss Payments (defined as the aggregate of all of the payments made or payable to Centennial Bank minus the aggregate of all of the payments made or payable to the FDIC) plus (C) the Period Servicing Amounts for any twelve-month period prior to and ending on the True-Up Measurement Date (defined as the product of the simple average of the principal amount of shared loss loans and shared loss assets (other than shared loss securities) at the beginning and end of such period times 1%).

In connection with the Coastal-Bayside, Wakulla and Gulf State acquisitions, the true-up payments would be equal to 50% of the excess, if any, of (i) 20% of an intrinsic loss estimate of $121.0 million in the case of Coastal, $24.0 million in the case of Bayside, $73.0 million in the case of Wakulla and $35.0 million in the case of Gulf State, less (ii) the sum of (A) 20% of the net loss amount (the sum of all losses less the sum of all recoveries on covered assets) plus (B) 25% of the asset premium (discount) plus (C) 3.5% of the total loans subject to loss sharing under the loss sharing agreements as specified in the schedules to the agreements.

The amount of FDIC-assisted acquisitions true-up accrued at September 30, 2013 and December 31, 2012 was $7.8 million and $7.1 million, respectively.

Table of Contents

Future Acquisitions

Liberty Bancshares, Inc. On October 24, 2013, Home BancShares, Inc. (Home), parent company of Centennial Bank (Centennial), completed its acquisition of Liberty Bancshares, Inc. (Liberty), parent company of Liberty Bank of Arkansas (Liberty Bank), pursuant to a previously announced definitive agreement and plan of merger whereby a wholly-owned acquisition subsidiary (Acquisition Sub) of Home merged with and into Liberty, resulting in Liberty becoming a wholly-owned subsidiary of Home. Immediately thereafter, Liberty Bank was merged into Centennial. Under the terms of the Agreement and Plan of Merger dated June 25, 2013 by and among Home, Centennial, Liberty, Liberty Bank and Acquisition Sub (the Merger Agreement), Home will issue 8,763,930 shares of its common stock valued at approximately $290.1 million as of October 23, 2013, plus $30.0 million in cash in exchange for all outstanding shares of Liberty common stock. As expected, Home also repurchased all of Liberty s SBLF preferred stock held by the U.S. Treasury shortly after the closing.

As of October 23, 2013, Liberty conducted banking business from 46 locations across Northeast, Northwest and Western Arkansas. Liberty held $2.82 billion in assets, $731.2 million in investment securities, $4.6 million of federal funds sold, $1.84 billion in loans, $82.9 million of bank premises and equipment, $34.8 million of foreclosed assets, $3.7 million in cash value of life insurance, $2.13 billion of deposits, $226.2 million of FHLB borrowed funds and $57.7 million of subordinated debentures.

The combined company now has approximately $7.0 billion in total assets, $5.4 billion in deposits, $4.4 billion in net loans, 153 branches, 186 ATMs, and 1,500 employees across Arkansas, Florida and Southern Alabama. The merger will significantly increase the Company s deposit market share in Arkansas making it the 2nd largest bank holding company headquartered in Arkansas.

The transaction is accretive to the Company s book value per common share and tangible book value per common share. On a pro forma basis as of September 30, 2013, the projected book value and tangible book value per common share are $12.84 and $8.04, respectively. Additionally the Leverage ratio, Tier 1 risk-based capital, Total risk-based capital and Tangible common equity ratio are projected to be 8.3%, 10.5%, 11.2% and 7.9%, respectively as of September 30, 2013 on a pro forma basis.

Due to the size of the Liberty acquisition, we anticipate there will be substantial merger related expenses recorded in the fourth quarter of 2013. These expenses will significantly impact our profitability for the fourth quarter of 2013.

See Note 23 Subsequent Events in the Condensed Notes to Consolidated Financial Statements for an additional discussion for the acquisition of Liberty Bank.

In the near term, our principal acquisition focus will be closing on the Liberty acquisition. After closing, we will then immediately concentrate on the integration of the core banking systems and corporate culture to achieve the projected efficiencies. As we progress with our plans for the Liberty acquisition, we will continue to evaluate our growth plans for the Company. We still believe properly priced future bank acquisitions can be a profitable growth strategy. At the appropriate time, our principal acquisition focus will once again be to expand our presence in Florida, Arkansas, South Alabama and other nearby markets. While we remain diligent in evaluating potential bank acquisition opportunities, our objective is to do what is in the best interest of our Company. Our goal in making these decisions is to maximize the return to our investors.

Branches

We intend to continue opening new (commonly referred to as de novo) branches in our current markets and in other attractive market areas if opportunities arise. During the third quarter, the Company opened two de novo branch locations; one on Highway 30A in Seagrove, Florida and the other in Pensacola, Florida. The Company currently has no plans for additional de novo branch locations. As a result of our acquisition of Premier Bank in the fourth quarter of 2012, three branches closed in the Tallahassee, FL area during the second quarter of 2013. During the fourth quarter of 2013, the Company has plans to close one branch in Panama City, Florida. The Company has 92 branches in Arkansas, 54 branches in Florida and 7 branches in Alabama as of October 24, 2013.

55

Table of Contents

Results of Operations

For Three Months Ended September 30, 2013 and 2012

Our net income increased $2.3 million or 14.1% to $18.4 million for the three-month period ended September 30, 2013, from $16.1 million for the same period in 2012. On a diluted earnings per common share basis, our earnings were $0.33 and $0.28 (split adjusted) for the three-month periods ended September 30, 2013 and 2012, respectively. The $2.3 million increase in net income is primarily associated with the additional net interest income and other non-interest income resulting from our 2012 acquisitions of Heritage and Premier. Furthermore, there was $1.2 million of additional gains from the sale of SBA loans, premises & equipment and OREO plus supplemental other income of $271,000 from the recovery of a prior year loss. There was also a reduction in the provision for loan losses of $167,000 in third quarter of 2013 when compared to the third quarter of 2012. These improvements were partially offset by a modest increase in the costs associated with the asset growth from our acquisitions and approximately $738,000 of additional merger expenses.

For Nine Months Ended September 30, 2013 and 2012

Our net income increased $7.5 million or 16.2% to $53.6 million for the nine-month period ended September 30, 2013, from $46.1 million for the same period in 2012. On a diluted earnings per common share basis, our earnings were $0.95 and $0.81 (split adjusted) for the nine-month periods ended September 30, 2013 and 2012, respectively. The $7.5 million increase in net income is primarily associated with the additional net interest income and other non-interest income resulting from our 2012 acquisitions of Vision, Heritage and Premier and a reduction in merger expenses by $925,000. Furthermore, there was $1.7 million of additional gains from the sale of SBA loans, premises & equipment, OREO and securities plus supplementary other income of $271,000 from the recovery of a prior year loss. There was also a reduction in the provision for loan losses of $650,000 in the first nine months of 2013 when compared to the first nine months 2012. These improvements were partially offset by a modest increase in the costs associated with the asset growth from our acquisitions.

Net Interest Income

Net interest income, our principal source of earnings, is the difference between the interest income generated by earning assets and the total interest cost of the deposits and borrowings obtained to fund those assets. Factors affecting the level of net interest income include the volume of earning assets and interest-bearing liabilities, yields earned on loans and investments and rates paid on deposits and other borrowings, the level of non-performing loans and the amount of non-interest-bearing liabilities supporting earning assets. Net interest income is analyzed in the discussion and tables below on a fully taxable equivalent basis. The adjustment to convert certain income to a fully taxable equivalent basis consists of dividing tax-exempt income by one minus the combined federal and state income tax rate (39.225% for the three and nine-month periods ended September 30, 2013 and 2012).

The Federal Reserve Board sets various benchmark rates, including the Federal Funds rate, and thereby influences the general market rates of interest, including the deposit and loan rates offered by financial institutions. The Federal Funds rate, which is the cost to banks of immediately available overnight funds, was lowered on December 16, 2008 to a historic low of 0.25% to 0% where it has remained since that time.

During the first quarter of 2013 impairment testing on the estimated cash flows of covered loans, five loan pools were determined to have a materially projected credit improvement. As a result of this improvement, the Company will recognize approximately $15.6 million as an adjustment to yield over the weighted average life of the loans with $1.9 million and $6.1 million of this amount being recognized during the three-month and nine-month periods ended

September 30, 2013, respectively.

Additionally, during the third quarter of 2013, one pool of our covered loans sharing common risk characteristics paid off in its entirety. As a result of this payoff we collected $1.9 million of unexpected cash flows. This unexpected positive cash flow resulted in the recognition of $1.9 million as an extra adjustment to yield on loans during the three-month and nine-month periods ended September 30, 2013.

Table of Contents

Net interest income on a fully taxable equivalent basis increased $7.7 million, or 19.3%, to $47.4 million for the three-month period ended September 30, 2013, from $39.7 million for the same period in 2012. This increase in net interest income was the result of a $5.6 million increase in interest income combined with a $2.1 million decrease in interest expense. The $5.6 million increase in interest income was primarily the result of a higher level of earning assets combined with higher yields on our covered loans. The $2.1 million decrease in interest expense for the three-month period ended September 30, 2013, is primarily the result of our interest bearing liabilities repricing in the lower interest rate environment combined with a decrease in the volume of our average time deposits and subordinated debentures. The repricing of our interest bearing liabilities in the lower interest rate environment resulted in a $1.5 million decrease in interest expense. The lower level of our average time deposits and subordinated debentures offset by increases in the remaining interest bearing liabilities resulted in a reduction in interest expense of approximately $620,000.

Net interest income on a fully taxable equivalent basis increased $21.1 million, or 17.9%, to $138.7 million for the nine-month period ended September 30, 2013, from $117.7 million for the same period in 2012. This increase in net interest income was the result of a $13.6 million increase in interest income combined with a $7.4 million decrease in interest expense. The $13.6 million increase in interest income was primarily the result of a higher level of earning assets combined with higher yields on our covered loans. The $7.4 million decrease in interest expense for the nine-month period ended September 30, 2013, is primarily the result of our interest bearing liabilities repricing in the lower interest rate environment combined with a decrease in the volume of our average time deposits, FHLB borrowed funds and subordinated debentures. The repricing of our interest bearing liabilities in the lower interest rate environment resulted in a $5.1 million decrease in interest expense. The lower level of our average time deposits, FHLB borrowed funds and subordinated debentures offset by increases in the remaining interest bearing liabilities resulted in a reduction in interest expense of approximately $2.3 million.

Net interest margin, on a fully taxable equivalent basis, was 5.41% and 5.25% for the three and nine months ended September 30, 2013 compared to 4.65% and 4.65% for the same periods in 2012, respectively. Our ability to improve pricing on interest bearing deposits combined with additional yield on FDIC loss sharing loans which more than offset the lower interest rates on newly originated loans in the loan portfolio during this historically low rate environment allowed the Company to expand net interest margin. The effective yield on non-covered loans for the three months ended September 30, 2013 and 2012 was 5.88% and 6.05%, respectively. The effective yield on non-covered loans for the nine months ended September 30, 2013 and 2012 was 6.01% and 6.16%, respectively. The effective yield on covered loans for the three months ended September 30, 2013 and 2012 was 12.76% and 7.84%, respectively. The effective yield on covered loans for the nine months ended September 30, 2013 and 2012 was 11.23% and 7.84%, respectively. Excluding the $3.8 million and $8.0 million of additional yield for third quarter and first nine months of 2013, respectively, the pro forma effective yield on covered loans was 7.98% and 8.13%, respectively.

When adjusted for the previously discussed $3.8 million of additional yield for third quarter, net interest margin, on a fully taxable equivalent basis, was 4.97% for the quarter just ended compared to 4.65% in the third quarter of 2012. When adjusted for the previously discussed $8.0 million of additional yield for first nine months of 2013, net interest margin, on a fully taxable equivalent basis, was 4.94% for the nine months just ended compared to 4.65% for the first nine months of 2012.

Table of Contents

Tables 1 and 2 reflect an analysis of net interest income on a fully taxable equivalent basis for the three and nine-month periods ended September 30, 2013 and 2012, as well as changes in fully taxable equivalent net interest margin for the three and nine-months period ended September 30, 2013, compared to the same periods in 2012.

Table 1: Analysis of Net Interest Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in thousands)			
Interest income	$ 49,176	$ 43,542	$ 145,409	$ 131,619
Fully taxable equivalent adjustment	1,073	1,112	3,199	3,353
Interest income fully taxable equivalent	50,249	44,654	148,608	134,972
Interest expense	2,826	4,917	9,869	17,301
Net interest income fully taxable equivalent	$ 47,423	$ 39,737	$ 138,739	$ 117,671
Yield on earning assets fully taxable equivalent	5.73%	5.23%	5.62%	5.33%
Cost of interest-bearing liabilities	0.41	0.68	0.46	0.80
Net interest spread fully taxable equivalent	5.32	4.55	5.16	4.53
Net interest margin fully taxable equivalent	5.41	4.65	5.25	4.65

Table 2: Changes in Fully Taxable Equivalent Net Interest Margin

	Three Months Ended September 30, 2013 vs. 2012	Nine Months Ended September 30, 2013 vs. 2012
	(In thousands)	
Increase (decrease) in interest income due to change in earning assets	$ 3,601	$ 11,479
Increase (decrease) in interest income due to change in earning asset yields	1,994	2,157
(Increase) decrease in interest expense due to change in interest-bearing liabilities	620	2,342
(Increase) decrease in interest expense due to change in interest rates paid on interest-bearing liabilities	1,471	5,090
Increase (decrease) in net interest income	$ 7,686	$ 21,068

Table of Contents

Table 3 shows, for each major category of earning assets and interest-bearing liabilities, the average amount outstanding, the interest income or expense on that amount and the average rate earned or expensed for the three and nine-month periods ended September 30, 2013 and 2012, respectively. The table also shows the average rate earned on all earning assets, the average rate expensed on all interest-bearing liabilities, the net interest spread and the net interest margin for the same periods. The analysis is presented on a fully taxable equivalent basis. Non-accrual loans were included in average loans for the purpose of calculating the rate earned on total loans.

Table 3: Average Balance Sheets and Net Interest Income Analysis

	Three Months Ended September 30,					
	2013			2012		
	Average Balance	Income / Expense	Yield / Rate	Average Balance	Income / Expense	Yield / Rate
	(Dollars in thousands)					
ASSETS						
Earnings assets						
Interest-bearing balances due from banks	$ 40,756	$ 19	0.18%	$ 192,192	$ 115	0.24%
Federal funds sold	4,411	2	0.18	3,749	3	0.32
Investment securities taxable	579,867	2,645	1.81	573,083	2,598	1.80
Investment securities non-taxable	183,341	2,462	5.33	160,252	2,512	6.24
Loans receivable	2,668,421	45,121	6.71	2,468,151	39,426	6.35
Total interest-earning assets	3,476,796	50,249	5.73	3,397,427	44,654	5.23
Non-earning assets	569,829			578,519		
Total assets	$ 4,046,625			$ 3,975,946		
LIABILITIES AND STOCKHOLDERS EQUITY						
Liabilities						
Interest-bearing liabilities						
Savings and interest-bearing transaction accounts	$ 1,691,077	$ 637	0.15%	$ 1,523,346	$ 774	0.20%
Time deposits	832,149	1,173	0.56	1,095,268	2,514	0.91
Total interest-bearing deposits	2,523,226	1,810	0.28	2,618,614	3,288	0.50
Federal funds purchased	1,511	3	0.79	15		0.00
Securities sold under agreement to repurchase	73,924	87	0.47	64,779	107	0.66
FHLB borrowed funds	144,467	910	2.50	131,599	1,040	3.14
Subordinated debentures	3,093	16	2.05	41,978	482	4.57
Total interest-bearing liabilities	2,746,221	2,826	0.41	2,856,985	4,917	0.68

Non-interest bearing liabilities						
Non-interest bearing deposits	738,526			597,287		
Other liabilities	27,315			20,695		
Total liabilities	3,512,062			3,474,967		
Stockholders equity	534,563			500,979		
Total liabilities and stockholders equity	$ 4,046,625			$ 3,975,946		
Net interest spread			5.32%			4.55%
Net interest income and margin		$ 47,423	5.41%		$ 39,737	4.65%

Table of Contents

Table 3: Average Balance Sheets and Net Interest Income Analysis

	Nine Months Ended September 30,					
	2013			2012		
	Average Balance	Income / Expense	Yield / Rate	Average Balance	Income / Expense	Yield / Rate
	(Dollars in thousands)					
ASSETS						
Earnings assets						
Interest-bearing balances due from banks	$ 108,646	$ 203	0.25%	$ 188,874	$ 327	0.23%
Federal funds sold	10,060	15	0.20	4,527	8	0.24
Investment securities taxable	571,375	7,538	1.76	580,492	8,518	1.96
Investment securities non-taxable	173,796	7,275	5.60	155,636	7,505	6.44
Loans receivable	2,672,088	133,577	6.68	2,451,553	118,614	6.46
Total interest-earning assets	3,535,965	148,608	5.62	3,381,082	134,972	5.33
Non-earning assets	592,438			577,227		
Total assets	$ 4,128,403			$ 3,958,309		
LIABILITIES AND STOCKHOLDERS EQUITY						
Liabilities						
Interest-bearing liabilities						
Savings and interest-bearing transaction accounts	$ 1,747,040	$ 2,191	0.17%	$ 1,457,121	$ 2,788	0.26%
Time deposits	906,015	4,233	0.62	1,188,074	9,324	1.05
Total interest-bearing deposits	2,653,055	6,424	0.32	2,645,195	12,112	0.61
Federal funds purchased	510	3	0.79	232		0.00
Securities sold under agreement to repurchase	72,078	253	0.47	68,425	328	0.64
FHLB borrowed funds	135,093	2,926	2.90	138,288	3,334	3.22
Subordinated debentures	11,023	263	3.19	43,541	1,527	4.68
Total interest-bearing liabilities	2,871,759	9,869	0.46	2,895,681	17,301	0.80
Non-interest bearing liabilities						
Non-interest bearing deposits	704,123			551,628		
Other liabilities	22,967			22,563		
Total liabilities	3,598,849			3,469,872		
Stockholders equity	529,554			488,437		

Total liabilities and stockholders equity	$ 4,128,403			$ 3,958,309		
Net interest spread			5.16%			4.53%
Net interest income and margin		$ 138,739	5.25%		$ 117,671	4.65%

60

Table of Contents

Table 4 shows changes in interest income and interest expense resulting from changes in volume and changes in interest rates for the three-month and nine-month periods ended September 30, 2013 compared to the same periods in 2012, on a fully taxable basis. The changes in interest rate and volume have been allocated to changes in average volume and changes in average rates, in proportion to the relationship of absolute dollar amounts of the changes in rates and volume.

Table 4: Volume/Rate Analysis

	Three Months Ended September 30, 2013 over 2012			Nine Months Ended September 30, 2013 over 2012		
	Volume	Yield/Rate	Total	Volume	Yield/Rate	Total
			(In thousands)			
Increase (decrease) in:						
Interest income:						
Interest-bearing balances due from banks	$ (75)	$ (21)	$ (96)	$ (148)	$ 24	$ (124)
Federal funds sold	1	(2)	(1)	8	(1)	7
Investment securities taxable	31	16	47	(132)	(848)	(980)
Investment securities non-taxable	336	(386)	(50)	822	(1,052)	(230)
Loans receivable	3,308	2,387	5,695	10,929	4,034	14,963
Total interest income	3,601	1,994	5,595	11,479	2,157	13,636
Interest expense:						
Interest-bearing transaction and savings deposits	78	(215)	(137)	485	(1,082)	(597)
Time deposits	(515)	(826)	(1,341)	(1,883)	(3,208)	(5,091)
Federal funds purchased		3	3		3	3
Securities sold under agreement to repurchase	14	(34)	(20)	17	(92)	(75)
FHLB borrowed funds	95	(225)	(130)	(76)	(332)	(408)
Subordinated debentures	(292)	(174)	(466)	(885)	(379)	(1,264)
Total interest expense	(620)	(1,471)	(2,091)	(2,342)	(5,090)	(7,432)
Increase (decrease) in net interest income	$ 4,221	$ 3,465	$ 7,686	$ 13,821	$ 7,247	$ 21,068

Provision for Loan Losses

Our management assesses the adequacy of the allowance for loan losses by applying the provisions of FASB ASC 310-10-35. Specific allocations are determined for loans considered to be impaired and loss factors are assigned to the remainder of the loan portfolio to determine an appropriate level in the allowance for loan losses. The allowance is increased, as necessary, by making a provision for loan losses. The specific allocations for impaired loans are assigned based on an estimated net realizable value after a thorough review of the credit relationship. The potential loss factors associated with the remainder of the loan portfolio are based on an internal net loss experience, as well as management s review of trends within the portfolio and related industries.

While general economic trends have improved recently, we cannot be certain that the current economic conditions will considerably improve in the near future. Recent and ongoing events at the national and international levels can create uncertainty in the financial markets. Despite these economic uncertainties, we continue to follow our historically conservative procedures for lending and evaluating the provision and allowance for loan losses. Our practice continues to be primarily traditional real estate lending with strong loan-to-value ratios.

Generally, commercial, commercial real estate, and residential real estate loans are assigned a level of risk at origination. Thereafter, these loans are reviewed on a regular basis. The periodic reviews generally include loan payment and collateral status, the borrowers financial data, and key ratios such as cash flows, operating income, liquidity, and leverage. A material change in the borrower s credit analysis can result in an increase or decrease in the loan s assigned risk grade. Aggregate dollar volume by risk grade is monitored on an on-going basis.

61

Our management reviews certain key loan quality indicators on a monthly basis, including current economic conditions, delinquency trends and ratios, portfolio mix changes, and other information management deems necessary. This review process provides a degree of objective measurement that is used in conjunction with periodic internal evaluations. To the extent that this review process yields differences between estimated and actual observed losses, adjustments are made to the loss factors used to determine the appropriate level of the allowance for loan losses.

Our Company is primarily a real estate lender in the markets we serve. As such, we are subject to declines in asset quality when real estate prices fall during a recession. The recent recession harshly impacted the real estate market in Florida. The economic conditions particularly in our Florida market have improved recently, although not to pre-recession levels. Our Arkansas markets economies have been fairly stable over the past several years with no boom or bust. As a result, the Arkansas economy fared better with its real estate values during this time period.

The provision for loan losses represents management s determination of the amount necessary to be charged against the current period s earnings, to maintain the allowance for loan losses at a level that is considered adequate in relation to the estimated risk inherent in the loan portfolio. There was zero provision for covered loans for the three months ended September 30, 2013. There was $100,000 provision for covered loans for the nine months ended September 30, 2013. There was $167,000 and $1.5 million provision for covered loans for the three and nine months ended September 30, 2012, respectively.

The provision for loan losses for covered loans for the three months ended September 30, 2013 was zero. The $100,000 of provision for loan losses for the nine months ended September 30, 2013 is a result of impairment testing on the estimated cash flows of the covered loans during the second quarter of 2013 which established that one pool evaluated had experienced material projected credit deterioration. As a result of this projection, we recorded a $500,000 provision for loan losses to the allowance for loan losses related to the purchased impaired loans at June 30, 2013. Since these loans are covered by loss share with the FDIC, we were able to increase the related indemnification asset by $400,000 resulting in a net provision for loan losses of $100,000.

The $167,000 and $1.5 million of provision for loan losses for the three and nine months ended September 30, 2012 is a result of impairment testing on the estimated cash flows of the covered loans during the second and third quarters of 2012 which established that two pools evaluated had experienced material projected credit deterioration. As a result of this projection, we recorded a $7.5 million provision for loan losses to the allowance for loan losses related to the purchased impaired loans at September 30, 2012. Since these loans are covered by loss share with the FDIC, we were able to increase the related indemnification asset by $6.0 million resulting in a net provision for loan losses of $1.5 million.

Our provision for loan losses for non-covered loans was zero for the three months ended September 30, 2013 and 2012. Our provision for loan losses for non-covered loans increased $750,000 for the nine months ended September 30, 2013, respectively, from zero for the nine months ended September 30, 2012. The net loans charged off for non-covered loans for the three and nine months ended September 30, 2013 were $2.9 million and $8.3 million compared to $2.6 million and $4.8 million for the same periods in 2012, respectively. Of the $2.9 million and $8.3 million net charged off for the non-covered impaired loans for the three and nine months ended September 30, 2013, approximately $15,000 and $1.2 million are from our Florida market, respectively. The remaining $2.8 million and $7.0 million predominately relates to net charge-offs on loans in our Arkansas market for the three and nine months ended September 30, 2013, respectively. See Allowance for Loan Losses in the Management s Discussion and Analysis for an additional discussion of Arkansas, Florida and Alabama charge-offs.

Our current or historical provision levels should not be relied upon as a predictor or indicator of future levels going forward.

62

Table of Contents

Non-Interest Income

Total non-interest income was $9.3 million and $28.1 million for the three-month and nine-month periods ended September 30, 2013, respectively, compared to $10.6 million and $31.8 million for the same periods in 2012, respectively. Our recurring non-interest income includes service charges on deposit accounts, other service charges and fees, mortgage lending, insurance, title fees, increase in cash value of life insurance, dividends and FDIC indemnification accretion/amortization.

Table 5 measures the various components of our non-interest income for the three-month and nine-month periods ended September 30, 2013 and 2012, respectively, as well as changes for the three-month and nine-month periods ended September 30, 2013 compared to the same periods in 2012.

Table 5: Non-Interest Income

	Three Months Ended September 30,		2013 Change from 2012		Nine Months Ended September 30,		2013 Change from 2012	
	2013	2012			2013	2012		
	(Dollars in thousands)							
Service charges on deposit accounts	$ 4,072	$ 3,834	$ 238	6.2%	$ 11,869	$ 11,007	$ 862	7.8%
Other service charges and fees	3,671	3,119	552	17.7	10,587	9,366	1,221	13.0
Mortgage lending income	1,527	1,550	(23)	(1.5)	4,518	3,731	787	21.1
Insurance commissions	519	512	7	1.4	1,642	1,501	141	9.4
Income from title services	156	112	44	39.3	401	329	72	21.9
Increase in cash value of life insurance	203	200	3	1.5	601	671	(70)	(10.4)
Dividends from FHLB, FRB, Bankers bank & other	179	182	(3)	(1.6)	755	532	223	41.9
Gain on sale of SBA loans	79	206	(127)	(61.7)	135	404	(269)	(66.6)
Gain (loss) on sale of premises and equipment, net	303	(5)	308	(6,160.0)	712	354	358	101.1
Gain (loss) on OREO, net	777	(222)	999	(450.0)	1,304	(170)	1,474	(867.1)
Gain (loss) on securities, net				0.0	111	10	101	1,010.0
FDIC indemnification accretion/(amortization), net	(3,177)	373	(3,550)	(951.7)	(7,452)	1,492	(8,944)	(599.5)
Other income	1,009	765	244	31.9	2,965	2,555	410	16.0

Total non-interest income	$ 9,318	$ 10,626	$ (1,308)	(12.3)%	$ 28,148	$ 31,782	$ (3,634)	(11.4)%

Non-interest income decreased $1.3 million, or 12.3%, to $9.3 million for the three-month period ended September 30, 2013 from $10.6 million for the same period in 2012. Non-interest income decreased $3.6 million, or 11.4%, to $28.1 million for the nine-month period ended September 30, 2013 from $31.8 million for the same period in 2012.

The primary factors that resulted in the three month decrease was an increase in amortization on our FDIC indemnification asset offset by improvements related to service charges on deposits, other service charges and fees, changes in OREO gains and gains on premises and equipment.

Additional details on some of the more significant changes are as follows:

The increase in service charges on deposit accounts and other service charges and fees are primarily from our 2012 acquisitions.

63

Table of Contents

The decrease in FDIC indemnification accretion/amortization, net is primarily associated with the impairment testing on the estimated cash flows of the covered loans during the first quarter of 2013 combined with a payoff during the third quarter of 2013 of one covered loan pool. As a result of the impairment testing, those loans were determined to have a materially projected credit improvement. Improvements in credit quality decrease the basis in the related indemnification asset. This positive event will reduce the indemnification asset by approximately $12.5 million of which $1.9 million was recognized for the three-month period ended September 30, 2013. The $12.5 million is being amortized over the weighted average life of the shared-loss agreement. As a result of the covered pool payoff, an additional $1.9 million of unexpected cash flows were recognized as an extra adjustment to yield on loans for the third quarter of 2013. This positive event reduced the indemnification asset by approximately $1.5 million of which the entire amount was recognized as a reduction of earnings for the third quarter of 2013.

The primary factors that resulted in the nine month decrease was an increase in amortization on our FDIC indemnification asset offset by improvements related to service charges on deposits, other service charges and fees, mortgage lending income, dividends from FHLB, FRB, Bankers bank & other, changes in OREO gains, gains on premises and equipment and gain on securities.

Additional details on some of the more significant changes are as follows:

The increase in service charges on deposit accounts and other service charges and fees are primarily from our 2012 acquisitions.

The increase in mortgage lending income is primarily related to increased mortgage lending activities resulting from the historically low rate environment during 2013 plus additional volume from the 2012 acquisitions.

The increase in dividends from FHLB, FRB, Bankers bank & other is primarily from a non-recurring dividend of approximately $231,000 from our investment in a private equity and venture capital firm which invests in small and lower middle market companies located in Arkansas and across the Midwest and Southeast United States.

The decrease in FDIC indemnification accretion/amortization, net is primarily associated with the impairment testing on the estimated cash flows of the covered loans during the first quarter of 2013 combined with a payoff during the third quarter of 2013 of one covered loan pool. As a result of the impairment testing, those loans were determined to have a materially projected credit improvement. Improvements in credit quality decrease the basis in the related indemnification asset. This positive event will reduce the indemnification asset by approximately $12.5 million of which $6.1 million was recognized for the nine-month period ended September 30, 2013. The $12.5 million is being amortized over the weighted average life of the shared-loss agreement. As a result of the covered pool payoff, an additional $1.9 million of unexpected cash flows were recognized as an extra adjustment to yield on loans for the third quarter of 2013. This positive event reduced the indemnification asset by approximately $1.5 million of which the entire amount was recognized as a reduction of earnings for the third quarter of 2013.

The increase in other income is primarily from $326,000 of tax-free life insurance proceeds during the first quarter of 2013. The proceeds were in connection with two former associates who were not currently with the Company.

Non-Interest Expense

Non-interest expense consists of salaries and employee benefits, occupancy and equipment, data processing, and other expenses such as advertising, merger and acquisition expenses, amortization of intangibles, electronic banking expense, FDIC and state assessment, insurance, other professional fees and legal and accounting fees.

64

Table of Contents

Table 6 below sets forth a summary of non-interest expense for the three-month and nine-month periods ended September 30, 2013 and 2012, as well as changes for the three-month and nine-month periods ended September 30, 2013 compared to the same periods in 2012.

Table 6: Non-Interest Expense

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	2013 Change from 2012		Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012	2013 Change from 2012	
	(Dollars in thousands)							
Salaries and employee benefits	$ 12,981	$ 11,652	$ 1,329	11.4%	$ 38,890	$ 34,941	$ 3,949	11.3%
Occupancy and equipment	4,010	3,805	205	5.4	11,498	10,788	710	6.6
Data processing expense	1,114	1,137	(23)	(2.0)	3,855	3,599	256	7.1
Other operating expenses:								
Advertising	363	534	(171)	(32.0)	1,176	1,898	(722)	(38.0)
Merger and acquisition expenses	1,034	296	738	249.3	1,063	1,988	(925)	(46.5)
Amortization of intangibles	802	694	108	15.6	2,406	2,018	388	19.2
Electronic banking expense	926	809	117	14.5	2,749	2,330	419	18.0
Directors fees	188	206	(18)	(8.7)	588	611	(23)	(3.8)
Due from bank service charges	136	137	(1)	(0.7)	437	412	25	6.1
FDIC and state assessment	684	588	96	16.3	1,991	1,742	249	14.3
Insurance	572	448	124	27.7	1,693	1,273	420	33.0
Legal and accounting	227	231	(4)	(1.7)	943	840	103	12.3
Other professional fees	404	411	(7)	(1.7)	1,367	1,263	104	8.2
Operating supplies	309	280	29	10.4	984	835	149	17.8
Postage	212	219	(7)	(3.2)	650	680	(30)	(4.4)
Telephone	291	270	21	7.8	885	792	93	11.7
Other expense	2,462	2,264	198	8.7	7,258	6,781	477	7.0
Total non-interest expense	$ 26,715	$ 23,981	$ 2,734	11.4%	$ 78,433	$ 72,791	$ 5,642	7.8%

Non-interest expense, excluding merger expenses, increased $2.0 million, or 8.4%, to $25.7 million for the three-month period ended September 30, 2013, from $23.7 million for the same period in 2012. Non-interest expense, excluding merger expenses, increased $6.6 million, or 9.3%, to $77.4 million for the nine-month period ended September 30, 2013, from $70.8 million for the same period in 2012. These increases primarily result from additional expense associated with the acquisitions during 2012. The decrease in advertising is primarily the result of management at its discretion deciding to spend a reduced amount of advertising during the quarter just ended and the first nine months of 2013.

Income Taxes

The provision for income taxes increased $1.6 million, or 17.6%, to $10.6 million for the three-month period ended September 30, 2013, from $9.0 million as of September 30, 2012. The provision for income taxes increased $5.1 million, or 19.9%, to $30.8 million for the nine-month period ended September 30, 2013, from $25.7 million as of September 30, 2012. The effective income tax rate was 36.6% and 36.5% for the three-month and nine-month periods ended September 30, 2013, respectively, compared to 35.9% and 35.8% for the same periods in 2012, respectively. The primary cause of the increase in taxes is the result of our higher earnings combined with our marginal tax rate of 39.225%.

65

Table of Contents

Financial Condition as of and for the Period Ended September 30, 2013 and December 31, 2012

Our total assets as of September 30, 2013 decreased $80.8 million to $4.16 billion from the $4.24 billion reported as of December 31, 2012. Our loan portfolio not covered by loss share increased by $47.6 million to $2.38 billion as of September 30, 2013, from $2.33 billion as of December 31, 2012. Our loan portfolio covered by loss share decreased by $76.8 million to $308.1 million as of September 30, 2013, from $384.9 million as of December 31, 2012. The decrease in covered loans is primarily associated with pay-downs and payoffs in our covered loan portfolio. Stockholders equity increased $29.7 million to $545.1 million as of September 30, 2013, compared to $515.5 million as of December 31, 2012. The annualized improvement in stockholders equity for the first nine months of 2012 was 7.7%. The increase in stockholders equity is primarily associated with the $40.2 million of comprehensive income less the $12.1 million of dividends paid for 2013.

Loans Receivable Not Covered by Loss Share

Our non-covered loan portfolio averaged $2.35 billion and $2.05 billion during the three-month periods ended September 30, 2013 and 2012, respectively. Our non-covered loan portfolio averaged $2.33 billion and $2.00 billion during the nine-month periods ended September 30, 2013 and 2012, respectively. Non-covered loans were $2.38 billion as of September 30, 2013, compared to $2.33 billion as of December 31, 2012. The relatively static state of the non-covered loan portfolio when compared to our historical expansion rates was not unexpected. This is primarily associated with lower loan demand and payoffs in our non-covered portfolios as our customers have grown more cautious in this weaker economy.

The most significant components of the non-covered loan portfolio were commercial real estate, residential real estate, consumer, and commercial and industrial loans. These non-covered loans are primarily originated within our market areas of Central Arkansas, North Central Arkansas, Southern Arkansas, the Florida Keys, Southwestern Florida, Central Florida, the Florida Panhandle and South Alabama, and are generally secured by residential or commercial real estate or business or personal property within our market areas.

As of September 30, 2013, we had $238.9 million of construction land development loans which were collateralized by land. This consisted of $149.6 million for raw land and $89.3 million for land with commercial and or residential lots.

Certain credit markets have experienced difficult conditions and volatility over the past several years, particularly Florida. Non-covered loans were $1.56 billion, $707.7 million and $106.9 million as of September 30, 2013 in Arkansas, Florida and Alabama, respectively.

Table 7 presents our loan balances not covered by loss share by category as of the dates indicated.

Table 7: Loan Portfolio Not Covered by Loss Share

	As of September 30, 2013	As of December 31, 2012
	(In thousands)	
Real estate:		
Commercial real estate loans:		
Non-farm/non-residential	$ 1,026,937	$ 1,019,039

Construction/land development	314,232	254,800
Agricultural	31,906	32,513
Residential real estate loans:		
Residential 1-4 family	529,732	549,269
Multifamily residential	117,639	129,742
Total real estate	2,020,446	1,985,363
Consumer	30,478	37,462
Commercial and industrial	268,900	256,908
Agricultural	30,612	19,825
Other	28,402	31,641
Loans receivable not covered by loss share	$ 2,378,838	$ 2,331,199

66

Non-Covered Commercial Real Estate Loans. We originate non-farm and non-residential loans (primarily secured by commercial real estate), construction/land development loans, and agricultural loans, which are generally secured by real estate located in our market areas. Our commercial mortgage loans are generally collateralized by first liens on real estate and amortized over a 15 to 25 year period with balloon payments due at the end of one to five years. These loans are generally underwritten by assessing cash flow (debt service coverage), primary and secondary source of repayment, the financial strength of any guarantor, the strength of the tenant (if any), the borrower s liquidity and leverage, management experience, ownership structure, economic conditions and industry specific trends and collateral. Generally, we will loan up to 85% of the value of improved property, 65% of the value of raw land and 75% of the value of land to be acquired and developed. A first lien on the property and assignment of lease is required if the collateral is rental property, with second lien positions considered on a case-by-case basis.

As of September 30, 2013, non-covered commercial real estate loans totaled $1.37 billion, or 57.7% of our non-covered loan portfolio, which is comparable to $1.31 billion, or 56.0% of our non-covered loan portfolio, as of December 31, 2012. Our Florida and Alabama non-covered commercial real estate loans are approximately 17.5% and 2.1% of our non-covered loan portfolio, respectively.

Non-Covered Residential Real Estate Loans. We originate one to four family, owner occupied residential mortgage loans generally secured by property located in our primary market areas. The majority of our non-covered residential mortgage loans consist of loans secured by owner occupied, single family residences. Non-covered residential real estate loans generally have a loan-to-value ratio of up to 90%. These loans are underwritten by giving consideration to the borrower s ability to pay, stability of employment or source of income, debt-to-income ratio, credit history and loan-to-value ratio.

As of September 30, 2013, non-covered residential real estate loans totaled $647.4 million, or 27.2% of our non-covered loan portfolio, compared to $679.0 million, or 29.1% of our non-covered loan portfolio, as of December 31, 2012. This decrease is primarily related to normal loan pay downs for these types of loans. Our Florida and Alabama non-covered residential real estate loans are approximately 10.0% and 1.8% of our non-covered loan portfolio, respectively.

Non-Covered Consumer Loans. Our non-covered consumer loan portfolio is composed of secured and unsecured loans originated by our banks. The performance of consumer loans will be affected by the local and regional economies as well as the rates of personal bankruptcies, job loss, divorce and other individual-specific characteristics.

As of September 30, 2013, our non-covered consumer loan portfolio totaled $30.5 million, or 1.3% of our total non-covered loan portfolio, compared to the $37.5 million, or 1.6% of our non-covered loan portfolio as of December 31, 2012. This decrease is associated with normal loan pay downs combined with reduced loan demand for these types of loans. Our Florida and Alabama non-covered consumer loans are less than 1% of our non-covered loan portfolio.

Non-Covered Commercial and Industrial Loans. Commercial and industrial loans are made for a variety of business purposes, including working capital, inventory, equipment and capital expansion. The terms for commercial loans are generally one to seven years. Commercial loan applications must be supported by current financial information on the borrower and, where appropriate, by adequate collateral. Commercial loans are generally underwritten by addressing cash flow (debt service coverage), primary and secondary sources of repayment, the financial strength of any guarantor, the borrower s liquidity and leverage, management experience, ownership structure, economic conditions and industry specific trends and collateral. The loan to value ratio depends on the type of collateral. Generally speaking, accounts receivable are financed at between 50% and 80% of accounts receivable less than 60 days past due. Inventory financing will range between 50% and 60% (with no work in process) depending on the borrower and nature of inventory. We require a first lien position for those loans.

As of September 30, 2013, non-covered commercial and industrial loans outstanding totaled $268.9 million, or 11.3% of our non-covered loan portfolio, which is comparable to $256.9 million, or 11.0% of our non-covered loan portfolio, as of December 31, 2012. Our Florida and Alabama non-covered commercial and industrial loans are approximately 1.5% and 0.6% of our non-covered loan portfolio, respectively.

Table of Contents

Total Loans Receivable

Table 8 presents total loans receivable by category.

Table 8: Total Loans Receivable

As of September 30, 2013

	Loans Receivable Not Covered by Loss Share	Loans Receivable Covered by FDIC Loss Share (In thousands)	Total Loans Receivable
Real estate:			
Commercial real estate loans			
Non-farm/non-residential	$ 1,026,937	$ 134,843	$ 1,161,780
Construction/land development	314,232	51,492	365,724
Agricultural	31,906	1,253	33,159
Residential real estate loans			
Residential 1-4 family	529,732	102,673	632,405
Multifamily residential	117,639	10,525	128,164
Total real estate	2,020,446	300,786	2,321,232
Consumer	30,478	17	30,495
Commercial and industrial	268,900	6,291	275,191
Agricultural	30,612		30,612
Other	28,402	978	29,380
Total	$ 2,378,838	$ 308,072	$ 2,686,910

Non-Performing Assets Not Covered by Loss Share

We classify our non-covered problem loans into three categories: past due loans, special mention loans and classified loans (accruing and non-accruing).

When management determines that a loan is no longer performing, and that collection of interest appears doubtful, the loan is placed on non-accrual status. Loans that are 90 days past due are placed on non-accrual status unless they are adequately secured and there is reasonable assurance of full collection of both principal and interest. Our management closely monitors all loans that are contractually 90 days past due, treated as special mention or otherwise classified or on non-accrual status.

We first reported non-covered loans acquired with deteriorated credit quality in our December 31, 2012 financial statements following our acquisitions of Heritage and Premier in the fourth quarter of 2012. The credit metrics most heavily impacted by our acquisition of acquired non-covered loans with deteriorated credit quality in our acquisitions of Heritage and Premier were the following credit quality indicators listed in Table 9 below:

Allowance for loan losses for non-covered loans to non-covered loans;

Non-performing non-covered assets to total non-covered assets; and

Non-performing non-covered loans to total non-covered loans.

On the date of acquisition, acquired credit-impaired loans are initially recognized at fair value, which incorporates the present value of amounts estimated to be collectible. As a result of the application of this accounting methodology, certain credit-related ratios, including those referenced above, may not necessarily be directly comparable with periods prior to the acquisition of the credit-impaired non-covered loans and non-covered non-performing assets, or comparable with other institutions.

Table of Contents

Table 9 sets forth information with respect to our non-performing non-covered assets as of September 30, 2013 and December 31, 2012. As of these dates, all non-performing non-covered restructured loans are included in non-accrual non-covered loans.

Table 9: Non-performing Assets Not Covered by Loss Share

	As of September 30, 2013	As of December 31, 2012
	(Dollars in thousands)	
Non-accrual non-covered loans	$ 17,187	$ 21,336
Non-covered loans past due 90 days or more (principal or interest payments)	11,248	5,937
Total non-performing non-covered loans	28,435	27,273
Other non-performing non-covered assets		
Non-covered foreclosed assets held for sale, net	14,158	20,393
Other non-performing non-covered assets	185	164
Total other non-performing non-covered assets	14,343	20,557
Total non-performing non-covered assets	$ 42,778	$ 47,830
Allowance for loan losses for non-covered loans to non-performing non-covered loans	132.38%	165.62%
Non-performing non-covered loans to total non-covered loans	1.20	1.17
Non-performing non-covered assets to total non-covered assets	1.15	1.30

Note: Purchased impaired non-covered loans are not classified as non-performing non-covered assets for the recognition of interest income as the pools are considered to be performing. However, for the purpose of calculating the non-performing credit metrics presented above, the Company has included all of the non-covered loans which are contractually 90 days past due and still accruing, including those in performing pools.

Our non-performing non-covered loans are comprised of non-accrual non-covered loans and accruing non-covered loans that are contractually past due 90 days. Our bank subsidiary recognizes income principally on the accrual basis of accounting. When loans are classified as non-accrual, the accrued interest is charged off and no further interest is accrued, unless the credit characteristics of the loan improve. If a loan is determined by management to be uncollectible, the portion of the loan determined to be uncollectible is then charged to the allowance for loan losses. The Florida franchise contains approximately 74.9% and 55.6% of our non-performing non-covered loans as of September 30, 2013 and December 31, 2012, respectively.

Total non-performing non-covered loans were $28.4 million as of September 30, 2013, compared to $27.3 million as of December 31, 2012 for an increase of $1.2 million. Of the $1.2 million increase in non-performing loans, $5.0 million is from a decrease in non-performing loans in our Arkansas market offset by a $6.1 million increase in non-performing loans in our Florida market and a $8,000 change in non-performing loans in Alabama. Non-performing loans at September 30, 2013 are approximately $7.1 million, $21.3 million and $8,000 in the Arkansas, Florida and Alabama markets, respectively.

Although the current state of the real estate market has improved, uncertainties still present in the national economy may continue to increase our level of non-performing non-covered loans. While we believe our allowance for loan losses is adequate at September 30, 2013, as additional facts become known about relevant internal and external factors that affect loan collectability and our assumptions, it may result in us making additions to the provision for loan losses during 2013. Our current or historical provision levels should not be relied upon as a predictor or indicator of future levels going forward.

Troubled debt restructurings (TDR) generally occur when a borrower is experiencing, or is expected to experience, financial difficulties in the near term. As a result, the Bank will work with the borrower to prevent further difficulties, and ultimately to improve the likelihood of recovery on the loan.

Table of Contents

During the recent real estate crisis, for the Nation in general and Florida in particular, it has become more common to restructure or modify the terms of certain loans under certain conditions. In those circumstances it may be beneficial to restructure the terms of a loan and work with the borrower for the benefit of both parties, versus forcing the property into foreclosure and having to dispose of it in an unfavorable and depressed real estate market. When we have modified the terms of a loan, we usually either reduce the monthly payment and/or interest rate for generally about three to twelve months. For our troubled debt restructurings that accrue interest at the time the loan is restructured, it would be a rare exception to have charged-off any portion of the loan. Only non-performing restructured loans are included in our non-performing non-covered loans. As of September 30, 2013, we had $48.4 million of non-covered restructured loans that are in compliance with the modified terms and are not reported as past due or non-accrual in Table 9. Our Florida market contains $29.2 million of these non-covered restructured loans.

To facilitate this process, a loan modification that might not otherwise be considered may be granted resulting in classification as a troubled debt restructuring. These loans can involve loans remaining on non-accrual, moving to non-accrual, or continuing on an accrual status, depending on the individual facts and circumstances of the borrower. Generally, a non-accrual loan that is restructured remains on non-accrual for a period of six months to demonstrate that the borrower can meet the restructured terms. However, performance prior to the restructuring, or significant events that coincide with the restructuring, are considered in assessing whether the borrower can pay the new terms and may result in the loan being returned to an accrual status after a shorter performance period. If the borrower s ability to meet the revised payment schedule is not reasonably assured, the loan will remain in a nonaccrual status.

The majority of the Bank s loan modifications relate to commercial lending and involve reducing the interest rate, changing from a principal and interest payment to interest-only, a lengthening of the amortization period, or a combination of some or all of the three. In addition, it is common for the Bank to seek additional collateral or guarantor support when modifying a loan. At September 30, 2013, the amount of troubled debt restructurings was $49.9 million, a decrease of 18.1% from $60.9 million at December 31, 2012. As of September 30, 2013 and December 31, 2012, 97.1% and 94.4%, respectively, of all restructured loans were performing to the terms of the restructure.

Total foreclosed assets held for sale not covered by loss share were $14.2 million as of September 30, 2013, compared to $20.4 million as of December 31, 2012 for a decrease of $6.2 million. The foreclosed assets held for sale not covered by loss share are comprised of $4.1 million of assets located in Florida with the remaining $10.1 million of assets located in Arkansas. As of September 30, 2013, there were no foreclosed assets not covered by loss share in Alabama.

During the first nine months of 2013, we had one non-covered foreclosed property greater than $1.0 million. This large development loan in northwest Arkansas has been in foreclosed assets since the first quarter of 2011. The carrying value was $3.6 million at September 30, 2013. The Company does not currently anticipate any additional losses on this property. No other foreclosed assets held for sale not covered by loss share have a carrying value greater than $1.0 million.

Table 10 shows the summary of foreclosed assets held for sale as of September 30, 2013 and December 31, 2012.

Table 10: Total Foreclosed Assets Held For Sale

	As of September 30, 2013	As of December 31, 2012
	Total	**Total**

	Not Covered by Loss Share	Covered by FDIC Loss Share		Not Covered by Loss Share	Covered by FDIC Loss Share	
			(In thousands)			
Commercial real estate loans						
Non-farm/non-residential	$ 8,266	$ 10,975	$ 19,241	$ 7,532	$ 9,024	$ 16,556
Construction/land development	2,772	8,395	11,167	7,343	13,586	20,929
Agricultural					599	599
Residential real estate loans						
Residential 1-4 family	3,120	4,950	8,070	5,518	8,317	13,835
Total foreclosed assets held for sale	$ 14,158	$ 24,320	$ 38,478	$ 20,393	$ 31,526	$ 51,919

Table of Contents

A loan is considered impaired when it is probable that we will not receive all amounts due according to the contracted terms of the loans. Impaired loans include non-performing loans (loans past due 90 days or more and non-accrual loans), criticized and/or classified loans with a specific allocation, loans categorized as TDR s and certain other loans identified by management that are still performing (loans included in multiple categories are only included once). As of September 30, 2013, average non-covered impaired loans were $103.5 million compared to $133.5 million as of December 31, 2012. As of September 30, 2013, non-covered impaired loans were $92.0 million compared to $127.2 million as of December 31, 2012 for a decrease of $35.2 million. This decrease is primarily associated with the improvements in loan balances with a specific allocation and loans categorized as TDR s. As of September 30, 2013, our Florida and Alabama markets accounted for approximately $48.0 million and $116,000 of the non-covered impaired loans, respectively.

We evaluated loans purchased in conjunction with the 2010 FDIC-assisted acquisitions and the 2012 acquisitions of Heritage and Premier for impairment in accordance with the provisions of FASB ASC Topic 310-30, *Loans and Debt Securities Acquired with Deteriorated Credit Quality*. Purchased loans are considered impaired if there is evidence of credit deterioration since origination and if it is probable that not all contractually required payments will be collected. All loans acquired in these transactions were deemed to be impaired loans. These loans were not classified as non-performing assets at September 30, 2013 and December 31, 2012, as the loans are accounted for on a pooled basis and the pools are considered to be performing. Therefore, interest income, through accretion of the difference between the carrying amount of the loans and the expected cash flows, is being recognized on all purchased impaired loans.

All non-covered loans acquired with deteriorated credit quality are considered impaired loans at the date of acquisition. Since the loans are accounted for on a pooled basis under ASC 310-30, individual loans are not classified as impaired.

Since the loans are accounted for on a pooled basis under ASC 310-30, individual loans subsequently restructured within the pools are not classified as TDRs in accordance with ASC 310-30-40. For non-covered loans acquired with deteriorated credit quality that were deemed TDRs prior to the Company s acquisition of them, these loans are also not considered TDRs as they are accounted for under ASC 310-30.

As of September 30, 2013 and December 31, 2012, there were no non-covered loans acquired with deteriorated credit quality on non-accrual status as a result of the loans being accounted for on the pool basis and the pools are considered to be performing for the accruing of interest income. Also, acquired loans contractually past due 90 days or more are accruing interest because the pools are considered to be performing for the purpose of accruing interest income.

Table of Contents

Past Due and Non-Accrual Loans

Table 11 shows the summary non-accrual loans as of September 30, 2013 and December 31, 2012:

Table 11: Total Non-Accrual Loans

	As of September 30, 2013			As of December 31, 2012		
	Not Covered by Loss Share	Covered by FDIC Loss Share	Total	Not Covered by Loss Share	Covered by FDIC Loss Share	Total
			(In thousands)			
Real estate:						
Commercial real estate loans						
Non-farm/non-residential	$ 4,520	$	$ 4,520	$ 3,659	$	$ 3,659
Construction/land development	1,536		1,536	2,680		2,680
Agricultural	98		98	140		140
Residential real estate loans						
Residential 1-4 family	9,398		9,398	9,972		9,972
Multifamily residential	336		336	3,215		3,215
Total real estate	15,888		15,888	19,666		19,666
Consumer	87		87	593		593
Commercial and industrial	1,212		1,212	1,077		1,077
Other						
Total non-accrual loans	$ 17,187	$	$ 17,187	$ 21,336	$	$ 21,336

If the non-accrual non-covered loans had been accruing interest in accordance with the original terms of their respective agreements, interest income of approximately $296,000 and $359,000 for the three-month periods ended September 30, 2013 and 2012, would have been recorded. If the non-accrual non-covered loans had been accruing interest in accordance with the original terms of their respective agreements, interest income of approximately $962,000 and $1.1 million for the nine-month periods ended September 30, 2013 and 2012, would have been recorded. The interest income recognized on the non-covered non-accrual loans for the three-month and nine-month periods ended September 30, 2013 and 2012 was considered immaterial.

Table 12 shows the summary of accruing past due loans 90 days or more as of September 30, 2013 and December 31, 2012:

Table 12: Total Loans Accruing Past Due 90 Days or More

As of September 30, 2013			As of December 31, 2012		
Not Covered by	Covered by FDIC	Total	Not Covered by	Covered by FDIC	Total

	Loss Share	Loss Share		Loss Share	Loss Share	
			(In thousands)			
Real estate:						
Commercial real estate loans						
Non-farm/non-residential	$ 3,989	$ 21,277	$ 25,266	$ 1,437	$ 32,227	$ 33,664
Construction/land development	1,866	9,467	11,333	1,296	14,962	16,258
Agricultural		183	183		548	548
Residential real estate loans						
Residential 1-4 family	4,473	12,679	17,152	2,589	20,005	22,594
Multifamily residential		347	347			
Total real estate	10,328	43,953	54,281	5,322	67,742	73,064
Consumer	37		37	95		95
Commercial and industrial	883	1,315	2,198	520	3,121	3,641
Other		531	531			
Total loans accruing past due 90 days or more	$ 11,248	$ 45,799	$ 57,047	$ 5,937	$ 70,863	$ 76,800

72

Table of Contents

The Company s total past due and non-accrual covered loans to total covered loans was 14.9% and 18.4% as of September 30, 2013 and December 31, 2012, respectively.

Allowance for Loan Losses for Non-Covered Loans

Overview. The allowance for loan losses for non-covered loans is maintained at a level which our management believes is adequate to absorb all probable losses on loans in the loan portfolio. The amount of the allowance is affected by: (i) loan charge-offs, which decrease the allowance; (ii) recoveries on loans previously charged off, which increase the allowance; and (iii) the provision of possible loan losses charged to income, which increases the allowance. In determining the provision for possible loan losses, it is necessary for our management to monitor fluctuations in the allowance resulting from actual charge-offs and recoveries and to periodically review the size and composition of the loan portfolio in light of current and anticipated economic conditions. If actual losses exceed the amount of allowance for loan losses for non-covered loans, our earnings could be adversely affected.

As we evaluate the allowance for loan losses for non-covered loans, we categorize it as follows: (i) specific allocations; (ii) allocations for criticized and classified assets with no specific allocation; (iii) general allocations for each major loan category; and (iv) miscellaneous allocations.

Specific Allocations. As a general rule, if a specific allocation is warranted, it is the result of an analysis of a previously classified credit or relationship. Typically, when it becomes evident through the payment history or a financial statement review that a loan or relationship is no longer supported by the cash flows of the asset and/or borrower and has become collateral dependent, we will use appraisals or other collateral analysis to determine if collateral impairment has occurred. The amount or likelihood of loss on this credit may not yet be evident, so a charge-off would not be prudent. However, if the analysis indicates that an impairment has occurred, then a specific allocation will be determined for this loan. If our existing appraisal is outdated or the collateral has been subject to significant market changes, we will obtain a new appraisal for this impairment analysis. The majority of the Company s impaired loans are collateral dependent at the present time, so third-party appraisals were used to determine the necessary impairment for these loans. Cash flow available to service debt was used for the other impaired loans. This analysis is performed each quarter in connection with the preparation of the analysis of the adequacy of the allowance for loan losses for non-covered loans, and if necessary, adjustments are made to the specific allocation provided for a particular loan.

For collateral dependent loans, we do not consider an appraisal outdated simply due to the passage of time. However, if market or other conditions have deteriorated and we believe that the current market value of the property is not within approximately 20% of the appraised value, we will consider the appraisal outdated and order a new appraisal for the impairment analysis. The recognition of any provision or related charge-off on a collateral dependent loan is either through annual credit analysis or, many times, when the relationship becomes delinquent. If the borrower is not current, we will update our credit and cash flow analysis to determine the borrower s repayment ability. If we determine this ability does not exist and it appears that the collection of the entire principal and interest is not likely, then the loan could be placed on non-accrual status. In any case, loans are classified as non-accrual no later than 105 days past due. If the loan requires a quarterly impairment analysis, this analysis is completed in conjunction with the completion of the analysis of the adequacy of the allowance for loan losses for non-covered loans. Any exposure identified through the impairment analysis is shown as a specific reserve on the individual impairment. If it is determined that a new appraisal is required, it is ordered and will be taken into consideration during the next completion of the impairment analysis.

Between the receipt of the original appraisal and the updated appraisal, we monitor the loan s repayment history and subject the loan to examination by our internal loan review. If the loan is over $1.0 million, our policy requires an annual credit review. In addition, we update all financial information and calculate the global repayment ability of the borrower/guarantors.

In estimating the net realizable value of the collateral, management may deem it appropriate to discount the appraisal based on the applicable circumstances. In such case, the amount charged off may result in loan principal outstanding being below fair value as presented in the appraisal.

As a general rule, when it becomes evident that the full principal and accrued interest of a loan may not be collected, or by law at 105 days past due, we will reflect that loan as non-performing. It will remain non-performing until it performs in a manner that it is reasonable to expect that we will collect the full principal and accrued interest.

When the amount or likelihood of a loss on a loan has been determined, a charge-off should be taken in the period it is determined. If a partial charge-off occurs, the quarterly impairment analysis will determine if the loan is still impaired, and thus continues to require a specific allocation.

Allocations for Criticized and Classified Assets not Individually Evaluated for Impairment. We establish allocations for loans rated special mention through loss in accordance with the guidelines established by the regulatory agencies. A percentage rate is applied to each loan category to determine the level of dollar allocation.

General Allocations. We establish general allocations for each major loan category. This section also includes allocations to loans, which are collectively evaluated for loss such as residential real estate, commercial real estate, consumer loans and commercial and industrial loans. The allocations in this section are based on a historical review of loan loss experience and past due accounts. We give consideration to trends, changes in loan mix, delinquencies, prior losses, and other related information.

Miscellaneous Allocations. Allowance allocations other than specific, classified, and general are included in our miscellaneous section.

Loans Collectively Evaluated for Impairment. Non-covered loans collectively evaluated for impairment increased organically by approximately $125.5 million for the quarter ended September 30, 2013 from $1.94 billion at December 31, 2012 to $2.07 billion at September 30, 2013. The percentage of the allowance for loan losses for non-covered loans allocated to non-covered loans collectively evaluated for impairment to the total non-covered loans collectively evaluated for impairment increased from 0.81% at December 31, 2012 to 1.06% at September 30, 2013. This increase is the result of the normal changes associated with the calculation of the allocation of the allowance for loan losses and includes routine changes from the previous year end reporting period such as organic loan growth, unallocated allowance, individual loan impairments, asset quality and net charge-offs.

Charge-offs and Recoveries. Total charge-offs increased to $5.1 million and $11.8 million for the three months and nine months ended September 30, 2013, respectively, compared to $4.0 million and $7.1 million for the same periods in 2012, respectively. Total recoveries increased to $2.2 million and $3.5 million for the three months and nine months ended September 30, 2013, respectively, compared to $1.4 million and $2.2 million for the same periods in 2012. For the three months ended September 30, 2013, the net charge-offs were $2.8 million for Arkansas, $15,000 for Florida and $8,000 for Alabama, respectively, equaling a net charge-off position of $2.9 million. For the nine months ended September 30, 2013, the net charge-offs were $7.0 million for Arkansas, $1.2 million for Florida and $19,000 for Alabama, respectively, equaling a net charge-off position of $8.3 million.

During the third quarter of 2013, there were $5.1 million in charge-offs and $2.2 million in recoveries. During the first nine months of 2013, there were $11.8 million in charge-offs and $3.5 million in recoveries. While the charge-offs and recoveries consisted of many relationships, there were three individual relationships consisting of charge-offs greater than $1.0 million. Two relationships were Arkansas relationships consisting of real estate loans for $2.9 million and $1.5 million totaling $4.4 million of debt. The total amount of charge-offs related to these relationships was $3.3 million, which consists of approximately $517,000 of residential 1-4 family, $1.3 million of multifamily residential and $1.5 million of non-farm/non-residential during the nine months ended 2013. The remaining loan relationship was a Florida relationship consisting of a non-farm/non-residential real estate loan totaling approximately $6.7 million of debt. The total amount of the charge-off associated with this relationship was $1.1 million during the nine months ended 2013.

We have not charged off an amount less than what was determined to be the fair value of the collateral as presented in the appraisal (for collateral dependent loans) for any period presented. Loans partially charged-off are placed on non-accrual status until it is proven that the borrower s repayment ability with respect to the remaining principal balance can be reasonably assured. This is usually established over a period of 6-12 months of timely payment performance.

Table of Contents

Table 13 shows the allowance for loan losses, charge-offs and recoveries for non-covered loans as of and for the three-month and nine-month periods ended September 30, 2013 and 2012.

Table 13: Analysis of Allowance for Loan Losses for Non-Covered Loans

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(Dollars in thousands)			
Balance, beginning of period	$ 40,498	$ 49,846	$ 45,170	$ 52,129
Loans charged off				
Real estate:				
Commercial real estate loans:				
Non-farm/non-residential	2,980	1,041	3,844	1,312
Construction/land development	392	525	560	838
Agricultural				
Residential real estate loans:				
Residential 1-4 family	787	1,475	2,713	2,575
Multifamily residential			2,291	95
Total real estate	4,159	3,041	9,408	4,820
Consumer	184	47	872	618
Commercial and industrial	438	549	619	758
Agricultural				
Other	320	347	881	858
Total loans charged off	5,101	3,984	11,780	7,054
Recoveries of loans previously charged off				
Real estate:				
Commercial real estate loans:				
Non-farm/non-residential	1,938	856	2,051	895
Construction/land development	4		19	7
Agricultural	1		1	233
Residential real estate loans:				
Residential 1-4 family	115	430	771	535
Multifamily residential	11		81	3
Total real estate	2,069	1,286	2,923	1,673
Consumer	33	28	123	96
Commercial and industrial	16	20	49	107
Agricultural				
Other	127	96	407	341
Total recoveries	2,245	1,430	3,502	2,217

Net loans charged off (recovered)	2,856	2,554	8,278	4,837
Provision for loan losses for non-covered loans			750	
Balance, September 30	$ 37,642	$ 47,292	$ 37,642	$ 47,292
Net charge-offs (recoveries) on loans not covered by loss share to average non-covered loans	0.48%	0.50%	0.48%	0.32%
Allowance for loan losses for non-covered loans to period end non-covered loans	1.58	2.28	1.58	2.28
Allowance for loan losses for non-covered loans to net charge-offs (recoveries)	332	465	340	732

75

Table of Contents

Allocated Allowance for Loan Losses for Non-Covered Loans. We use a risk rating and specific reserve methodology in the calculation and allocation of our allowance for loan losses for non-covered loans. While the allowance is allocated to various loan categories in assessing and evaluating the level of the allowance, the allowance is available to cover charge-offs incurred in all loan categories. Because a portion of our portfolio has not matured to the degree necessary to obtain reliable loss data from which to calculate estimated future losses, the unallocated portion of the allowance is an integral component of the total allowance. Although unassigned to a particular credit relationship or product segment, this portion of the allowance is vital to safeguard against the imprecision inherent in estimating credit losses.

The changes for the period ended September 30, 2013 and the year ended December 31, 2012 in the allocation of the allowance for loan losses for non-covered loans for the individual types of loans are primarily associated with changes in the ASC 310 calculations, both individual and aggregate, and changes in the ASC 450 calculations. These calculations are affected by changes in individual loan impairments, changes in asset quality, net charge-offs during the period and normal changes in the outstanding loan portfolio, as well any changes to the general allocation factors due to changes within the actual characteristics of the loan portfolio.

Table 14 presents the allocation of allowance for loan losses for non-covered loans as of September 30, 2013 and December 31, 2012.

Table 14: Allocation of Allowance for Loan Losses for Non-Covered Loans

	As of September 30, 2013		**As of December 31, 2012**	
	Allowance Amount	**% of loans(1)**	**Allowance Amount**	**% of loans(1)**
	(Dollars in thousands)			
Real estate:				
Commercial real estate loans:				
Non-farm/non-residential	$ 16,517	43.2%	$ 19,781	43.7%
Construction/land development	6,475	13.2	5,816	10.9
Agricultural	241	1.3	193	1.4
Residential real estate loans:				
Residential 1-4 family	5,936	22.3	10,467	23.6
Multifamily residential	2,127	4.9	3,346	5.6
Total real estate	31,296	84.9	39,603	85.2
Consumer	463	1.3	894	1.6
Commercial and industrial	2,190	11.3	3,870	11.0
Agricultural	588	1.3	394	0.8
Other		1.2		1.4
Unallocated	3,105		409	
Total	$ 37,642	100.0%	$ 45,170	100.0%

(1) Percentage of loans in each category to loans receivable not covered by loss share.

Allowance for Loan Losses for Covered Loans

Allowance for loan losses for covered loans were $1.1 million and $5.5 million at September 30, 2013 and December 31, 2012, respectively.

Total charge-offs decreased to zero for the three months ended September 30, 2013, compared to $354,000 for the same period in 2012. Total recoveries increased to $154,000 for the three months ended September 30, 2013, compared to zero for the same period in 2012. There was zero and $167,000 of provision for loan losses taken on covered loans during the three months ended September 30, 2013 and 2012, respectively.

Total charge-offs increased to $5.0 million for the nine months ended September 30, 2013, compared to $354,000 for the same period in 2012. Total recoveries increased to $171,000 for the nine months ended September 30, 2013, compared to zero for the same period in 2012. There was $100,000 and $1.5 million of provision for loan losses taken on covered loans during the nine months ended September 30, 2013 and 2012, respectively.

Table of Contents

Investments and Securities

Our securities portfolio is the second largest component of earning assets and provides a significant source of revenue. Securities within the portfolio are classified as held-to-maturity, available-for-sale, or trading based on the intent and objective of the investment and the ability to hold to maturity. Fair values of securities are based on quoted market prices where available. If quoted market prices are not available, estimated fair values are based on quoted market prices of comparable securities. As of September 30, 2013 we had $9.5 million of held-to-maturity securities. All of the held-to-maturity securities were invested in state and political subdivisions as of September 30, 2013. As of December 31, 2012, we had no held-to-maturity or trading securities.

Securities available-for-sale are reported at fair value with unrealized holding gains and losses reported as a separate component of stockholders equity as other comprehensive income. Securities that are held as available-for-sale are used as a part of our asset/liability management strategy. Securities may be sold in response to interest rate changes, changes in prepayment risk, the need to increase regulatory capital, and other similar factors are classified as available-for-sale. Available-for-sale securities were $839.6 million as of September 30, 2013, compared to $726.2 million as of December 31, 2012. The estimated effective duration of our securities portfolio was 3.6 years as of September 30, 2013.

As of September 30, 2013, $404.2 million, or 48.2%, of our available-for-sale securities were invested in mortgage-backed securities, compared to $325.3 million, or 44.8%, of our available-for-sale securities as of December 31, 2012. To reduce our income tax burden, $200.9 million, or 23.9%, of our available-for-sale securities portfolio as of September 30, 2013, was primarily invested in tax-exempt obligations of state and political subdivisions, compared to $190.6 million, or 26.3%, of our available-for-sale securities as of December 31, 2012. Also, we had approximately $183.2 million, or 21.8%, invested in obligations of U.S. Government-sponsored enterprises as of September 30, 2013, compared to $190.7 million, or 26.3%, of our available-for-sale securities as of December 31, 2012.

Certain investment securities are valued at less than their historical cost. These declines are primarily the result of the rate for these investments yielding less than current market rates. Based on evaluation of available evidence, we believe the declines in fair value for these securities are temporary. It is our intent to hold these securities to recovery. Should the impairment of any of these securities become other than temporary, the cost basis of the investment will be reduced and the resulting loss recognized in net income in the period the other than temporary impairment is identified.

See Note 3 Investment Securities to the Condensed Notes to Consolidated Financial Statements for the carrying value and fair value of investment securities.

Deposits

Our deposits averaged $3.26 billion and $3.36 billion for the three-month and nine-month periods ended September 30, 2013. Total deposits decreased $234.6 million, or an annualized decrease of 9.0%, to $3.25 billion as of September 30, 2013, from $3.48 billion as of December 31, 2012. Deposits are our primary source of funds. We offer a variety of products designed to attract and retain deposit customers. Those products consist of checking accounts, regular savings deposits, NOW accounts, money market accounts and certificates of deposit. Deposits are gathered from individuals, partnerships and corporations in our market areas. In addition, we obtain deposits from state and local entities and, to a lesser extent, U.S. Government and other depository institutions.

Our policy also permits the acceptance of brokered deposits. As of September 30, 2013 and December 31, 2012, brokered deposits were $23.8 million and $56.9 million, respectively. Included in these brokered deposits are $19.6 million and $52.5 million of Certificate of Deposit Account Registry Service (CDARS) as of September 30, 2013 and December 31, 2012, respectively. CDARS are deposits of our customers we have swapped with other institutions. This gives our customers the potential for FDIC insurance of up to $50 million.

Table of Contents

The interest rates paid are competitively priced for each particular deposit product and structured to meet our funding requirements. We will continue to manage interest expense through deposit pricing. We may allow higher rate deposits to run off during this current period of limited loan demand. We believe that additional funds can be attracted and deposit growth can be realized through deposit pricing if we experience increased loan demand or other liquidity needs.

The Federal Reserve Board sets various benchmark rates, including the Federal Funds rate, and thereby influences the general market rates of interest, including the deposit and loan rates offered by financial institutions. The Federal Funds rate, which is the cost to banks of immediately available overnight funds, was lowered on December 16, 2008 to a historic low of 0.25% to 0% where it has remained since that time.

Table 15 reflects the classification of the average deposits and the average rate paid on each deposit category, which is in excess of 10 percent of average total deposits, for the three-month and nine-month periods ended September 30, 2013 and 2012.

Table 15: Average Deposit Balances and Rates

	Three Months Ended September 30,			
	2013		2012	
	Average Amount	Average Rate Paid	Average Amount	Average Rate Paid
	(Dollars in thousands)			
Non-interest-bearing transaction accounts	$ 738,526	%	$ 597,287	%
Interest-bearing transaction accounts	1,469,958	0.16	1,351,319	0.28
Savings deposits	221,119	0.05	172,027	0.16
Time deposits:				
$100,000 or more	427,422	0.71	606,410	1.13
Other time deposits	404,727	0.40	488,858	0.64
Total	$ 3,261,752	0.22%	$ 3,215,901	0.44%

	Nine Months Ended September 30,			
	2013		2012	
	Average Amount	Average Rate Paid	Average Amount	Average Rate Paid
	(Dollars in thousands)			
Non-interest-bearing transaction accounts	$ 704,123	%	$ 551,628	%
Interest-bearing transaction accounts	1,532,649	0.18	1,294,434	0.19
Savings deposits	214,391	0.08	162,687	0.11
Time deposits:				
$100,000 or more	473,704	0.80	665,521	1.27
Other time deposits	432,311	0.43	522,553	0.77
Total	$ 3,357,178	0.26%	$ 3,196,823	0.47%

Securities Sold Under Agreements to Repurchase

We enter into short-term purchases of securities under agreements to resell (resale agreements) and sales of securities under agreements to repurchase (repurchase agreements) of substantially identical securities. The amounts advanced under resale agreements and the amounts borrowed under repurchase agreements are carried on the balance sheet at the amount advanced. Interest incurred on repurchase agreements is reported as interest expense. Securities sold under agreements to repurchase increased $5.0 million, or 7.6%, from $66.3 million as of December 31, 2012 to $71.3 million as of September 30, 2013.

Table of Contents

FHLB Borrowed Funds

Our FHLB borrowed funds were $270.2 million and $130.4 million at September 30, 2013 and December 31, 2012, respectively. At September 30, 2013, $170.0 million and $100.2 million of the outstanding balance were short-term and long-term advances, respectively. All of the outstanding balance at December 31, 2012 was long-term advances. Our remaining FHLB borrowing capacity was $632.5 million and $640.5 million as of September 30, 2013 and December 31, 2012, respectively. Expected maturities will differ from contractual maturities, because FHLB may have the right to call or prepay certain obligations.

Subordinated Debentures

Subordinated debentures, which consist of guaranteed payments on trust preferred securities, were $3.1 million and $28.9 million as of September 30, 2013 and December 31, 2012, respectively.

The trust preferred securities are tax-advantaged issues that qualify for Tier 1 capital treatment subject to certain limitations. Distributions on these securities are included in interest expense. Each of the trusts is a statutory business trust organized for the sole purpose of issuing trust securities and investing the proceeds in our subordinated debentures, the sole asset of each trust. The trust preferred securities of each trust represent preferred beneficial interests in the assets of the respective trusts and are subject to mandatory redemption upon payment of the subordinated debentures held by the trust. We wholly own the common securities of each trust. Each trust s ability to pay amounts due on the trust preferred securities is solely dependent upon our making payment on the related subordinated debentures. Our obligations under the subordinated securities and other relevant trust agreements, in aggregate, constitute a full and unconditional guarantee by us of each respective trust s obligations under the trust securities issued by each respective trust.

Presently, the funds raised from the trust preferred offerings qualify as Tier 1 capital for regulatory purposes, subject to the applicable limit, with the balance qualifying as Tier 2 capital. The Board of Governors of the Federal Reserve System recently announced the planned implementation of Basel III capital rules. Under these rules trust preferred securities will be phased out as Tier 1 capital for future periods.

As of December 31, 2012, the Company held $28.9 million of trust preferred securities currently callable without penalty based on the terms of the specific agreements. Since these trust preferred securities are being phased out of Tier 1 capital, we have decided to begin the process of redeeming these instruments. During the first quarter of 2013, we redeemed approximately $25.8 million in trust preferred securities. As a result of the Liberty acquisition, we are not projecting the Company to pay-off the remaining balance during 2013.

Stockholders Equity

Stockholders equity was $545.1 million at September 30, 2013 compared to $515.5 million at December 31, 2012, an increase of 5.8%. As of September 30, 2013 and December 31, 2012 our equity to asset ratio was 13.1% and 12.2% respectively. Book value per share was $9.69 at September 30, 2013 compared to $9.17 (split adjusted) at December 31, 2012, a 7.6% annualized increase.

Common Stock Cash Dividends. We declared cash dividends on our common stock of $0.075 per share and $0.06 per share for the three-month periods ended September 30, 2013 and 2012 and $0.215 and $0.16 per share for the nine-month periods ended September 30, 2013 and 2012. The common stock dividend payout ratio for the three months ended September 30, 2013 and 2012 was 23.0% and 21.0%, respectively. The common stock dividend payout ratio for the nine months ended September 30, 2013 and 2012 was 22.6% and 19.6%, respectively. For the fourth quarter of 2013, the Board of Directors declared a regular $0.075 per share quarterly cash dividend payable December 4, 2013, to shareholders of record November 13, 2013.

Two-for-One Stock Split. On April 18, 2013, our Board of Directors declared a two-for-one stock split paid in the form of a 100% stock dividend on June 12, 2013 (the Payment Date) to shareholders of record at the close of business on May 22, 2013. The additional shares were distributed by the Company s transfer agent, Computershare, and the Company s common stock began trading on a split-adjusted basis on the NASDAQ Global Select Market on June 13, 2013. The stock split increased the Company s total shares of common stock outstanding as of June 12, 2013 from 28,121,596 shares to 56,243,192 shares.

Table of Contents

All previously reported share and per share amounts have been restated to reflect the retroactive effect of the stock split.

Liquidity and Capital Adequacy Requirements

Risk-Based Capital. We as well as our bank subsidiary are subject to various regulatory capital requirements administered by the federal banking agencies. Failure to meet minimum capital requirements can initiate certain mandatory and other discretionary actions by regulators that, if enforced, could have a direct material effect on our financial statements. Under capital adequacy guidelines and the regulatory framework for prompt corrective action, we must meet specific capital guidelines that involve quantitative measures of our assets, liabilities and certain off-balance-sheet items as calculated under regulatory accounting practices. Our capital amounts and classifications are also subject to qualitative judgments by the regulators as to components, risk weightings and other factors.

Quantitative measures established by regulation to ensure capital adequacy require us to maintain minimum amounts and ratios (set forth in the table below) of total and Tier 1 capital to risk-weighted assets, and of Tier 1 capital to average assets. Management believes that, as of September 30, 2013 and December 31, 2012, we met all regulatory capital adequacy requirements to which we were subject.

Table 16 presents our risk-based capital ratios as of September 30, 2013 and December 31, 2012.

Table 16: Risk-Based Capital

	As of September 30, 2013	As of December 31, 2012
	(Dollars in thousands)	
Tier 1 capital		
Stockholders equity	$ 545,142	$ 515,473
Qualifying trust preferred securities	3,000	28,000
Goodwill and core deposit intangibles, net	(94,525)	(96,785)
Unrealized (gain) loss on available-for-sale securities	1,364	(12,001)
Deferred tax assets	(547)	(3,529)
Total Tier 1 capital	454,434	431,158
Tier 2 capital		
Qualifying allowance for loan losses	38,748	38,807
Total Tier 2 capital	38,748	38,807
Total risk-based capital	$ 493,182	$ 469,965
Average total assets for leverage ratio	$ 3,951,553	$ 3,939,206
Risk weighted assets	$ 3,201,009	$ 3,092,707

Ratios at end of period		
Leverage ratio	11.50%	10.95%
Tier 1 risk-based capital	14.20	13.94
Total risk-based capital	15.41	15.20
Minimum guidelines		
Leverage ratio	4.00%	4.00%
Tier 1 risk-based capital	4.00	4.00
Total risk-based capital	8.00	8.00

As of the most recent notification from regulatory agencies, our bank subsidiary was well-capitalized under the regulatory framework for prompt corrective action. To be categorized as well-capitalized , our banking subsidiary and we must maintain minimum leverage, Tier 1 risk-based capital, and total risk-based capital ratios as set forth in the table. There are no conditions or events since that notification that we believe have changed the bank subsidiary s category.

Table of Contents

Non-GAAP Financial Measurements

We had $95.3 million, $97.7 million, and $86.9 million total goodwill, core deposit intangibles and other intangible assets as of September 30, 2013, December 31, 2012 and September 30, 2012, respectively. Because of our level of intangible assets and related amortization expenses, management believes diluted earnings per common share excluding intangible amortization, tangible book value per common share, return on average assets excluding intangible amortization, return on average tangible common equity excluding intangible amortization and tangible common equity to tangible assets are useful in evaluating our company. These calculations, which are similar to the GAAP calculation of diluted earnings per common share, book value, return on average assets, return on average common equity, and common equity to assets, are presented in Tables 17 through 21, respectively. All per share data has been restated to reflect the retroactive effect of the two-for-one stock split which occurred during June 2013.

Table 17: Diluted Earnings Per Share Excluding Intangible Amortization

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(In thousands, except per share data)			
GAAP net income	$ 18,363	$ 16,095	$ 53,570	$ 46,083
Intangible amortization after-tax	487	421	1,462	1,226
Earnings excluding intangible amortization	$ 18,850	$ 16,516	$ 55,032	$ 47,309
GAAP diluted earnings per share	$ 0.33	$ 0.28	$ 0.95	$ 0.81
Intangible amortization after-tax		0.01	0.02	0.02
Diluted earnings per share excluding intangible amortization	$ 0.33	$ 0.29	$ 0.97	$ 0.83

Table 18: Tangible Book Value Per Share

	As of September 30, 2013	As of December 31, 2012
	(Dollars in thousands, except per share data)	
Book value per share: A/B	$ 9.69	$ 9.17
Tangible book value per share: (A-C-D)/B	7.99	7.43
(A) Total equity	$ 545,142	$ 515,473
(B) Shares outstanding	56,278	56,213
(C) Goodwill	$ 85,681	$ 85,681
(D) Core deposit and other intangibles	9,655	12,061

Table of Contents

Table 19: Return on Average Assets Excluding Intangible Amortization

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(Dollars in thousands)			
Return on average assets: A/C	1.80%	1.61%	1.73%	1.56%
Return on average assets excluding intangible amortization: B/(C-D)	1.89	1.69	1.82	1.63
(A) Net income	$ 18,363	$ 16,095	$ 53,570	$ 46,083
Intangible amortization after-tax	487	421	1,462	1,226
(B) Earnings excluding intangible amortization	$ 18,850	$ 16,516	$ 55,032	$ 47,309
(C) Average assets	$ 4,046,625	$ 3,975,946	$ 4,128,403	$ 3,958,309
(D) Average goodwill, core deposits and other intangible assets	95,723	87,213	96,521	84,869

Table 20: Return on Average Tangible Equity Excluding Intangible Amortization

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(Dollars in thousands)			
Return on average equity: A/C	13.63%	12.78%	13.53%	12.60%
Return on average tangible equity excluding intangible amortization: B/(C-D)	17.04	15.88	16.99	15.66
(A) Net income	$ 18,363	$ 16,095	$ 53,570	$ 46,083
(B) Earnings excluding intangible amortization	18,850	16,516	55,032	47,309
(C) Average equity	534,563	500,979	529,554	488,437
(D) Average goodwill, core deposits and other intangible assets	95,723	87,213	96,521	84,869

Table 21: Tangible Equity to Tangible Assets

	As of September 30, 2013	As of December 31, 2012
	(Dollars in thousands)	
Equity to assets: B/A	13.10%	12.15%
Tangible equity to tangible assets: (B-C-D)/(A-C-D)	11.06	10.08

(A) Total assets	$ 4,161,306	$ 4,242,130
(B) Total equity	545,142	515,473
(C) Goodwill	85,681	85,681
(D) Core deposit and other intangibles	9,655	12,061

Table of Contents

We have $490.2 million of purchased non-covered loans, which includes $77.4 million of discount for credit losses on non-covered loans acquired at September 30, 2013. We had $569.7 million of purchased non-covered loans, which included $81.7 million of discount for credit losses on non-covered loans acquired at December 31, 2012. For purchased credit-impaired financial assets, GAAP requires a discount embedded in the purchase price that is attributable to the expected credit losses at the date of acquisition, which is a different approach from non-purchased-credit-impaired assets. While the discount for credit losses on purchased non-covered loans is not available for credit losses on non-purchased non-covered loans, management believes it is useful information to show the same accounting as if applied to all loans, including those acquired in a business combination. Therefore, management believes the allowance for loan losses for non-covered loans plus discount for credit losses on non-covered loans acquired to total non-covered loans plus discount for credit losses on non-covered loans acquired is useful in evaluating our Company. This calculation, which is similar to the GAAP calculation of allowance for loan losses for non-covered loans to total non-covered loans, is presented in Table 22 below.

Table 22: Allowance for Loan Losses for Non-Covered Loans to Total Non-Covered Loans

	As of September 30, 2013		
	Non-Covered Loans	Purchased Non-Covered Loans	Total
	(Dollars in thousands)		
Loan balance reported (A)	$ 1,966,070	$ 412,768	$ 2,378,838
Loan balance reported plus discount (B)	1,966,070	490,181	2,456,251
Allowance for loan losses for non-covered loans (C)	$ 37,642	$	$ 37,642
Discount for credit losses on non-covered loans acquired (D)		77,413	77,413
Total allowance for loan losses for non-covered loans plus discount for credit losses on non-covered loans acquired (E)	$ 37,642	$ 77,413	$ 115,055
Allowance for loan losses for non-covered loans to total non-covered loans (C/A)	1.91%	N/A	1.58%
Discount for credit losses on non-covered loans acquired to non-covered loans acquired plus discount for credit losses on non-covered loans acquired (D/B)	N/A	15.79%	N/A
Allowance for loan losses for non-covered loans plus discount for credit losses on non-covered loans acquired to total non-covered loans plus discount for credit losses on non-covered loans acquired (E/B)	N/A	N/A	4.68%

Note: Discount for credit losses on purchased credit impaired loans acquired are accounted for on a pool by pool basis and are not available to cover credit losses on non-acquired loans or other pools.

Table of Contents

	As of December 31, 2012		
	Non-Covered Loans	Purchased Non-Covered Loans	Total
	(Dollars in thousands)		
Loan balance reported (A)	$ 1,843,249	$ 487,950	$ 2,331,199
Loan balance reported plus discount (B)	1,843,249	569,667	2,412,916
Allowance for loan losses for non-covered loans (C)	$ 45,170	$	$ 45,170
Discount for credit losses on non-covered loans acquired (D)		81,717	81,717
Total allowance for loan losses for non-covered loans plus discount for credit losses on non-covered loans acquired (E)	$ 45,170	$ 81,717	$ 126,887
Allowance for loan losses for non-covered loans to total non-covered loans (C/A)	2.45%	N/A	1.94%
Discount for credit losses on non-covered loans acquired to non-covered loans acquired plus discount for credit losses on non-covered loans acquired (D/B)	N/A	14.34%	N/A
Allowance for loan losses for non-covered loans plus discount for credit losses on non-covered loans acquired to total non-covered loans plus discount for credit losses on non-covered loans acquired (E/B)	N/A	N/A	5.26%

Note: Discount for credit losses on purchased credit impaired loans acquired are accounted for on a pool by pool basis and are not available to cover credit losses on non-acquired loans or other pools.

Recently Issued Accounting Pronouncements

See Note 22 to the Condensed Notes to Consolidated Financial Statements for a discussion of certain recently issued and recently adopted accounting pronouncements.

Item 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Liquidity and Market Risk Management

Liquidity Management. Liquidity refers to the ability or the financial flexibility to manage future cash flows to meet the needs of depositors and borrowers and fund operations. Maintaining appropriate levels of liquidity allows us to have sufficient funds available for reserve requirements, customer demand for loans, withdrawal of deposit balances and maturities of deposits and other liabilities. Our primary source of liquidity at our holding company is dividends paid by our bank subsidiary. Applicable statutes and regulations impose restrictions on the amount of dividends that may be declared by our bank subsidiary. Further, any dividend payments are subject to the continuing ability of the bank subsidiary to maintain compliance with minimum federal regulatory capital requirements and to retain its characterization under federal regulations as a well-capitalized institution.

Our bank subsidiary has potential obligations resulting from the issuance of standby letters of credit and commitments to fund future borrowings to our loan customers. Many of these obligations and commitments to fund future borrowings to our loan customers are expected to expire without being drawn upon, therefore the total commitment amounts do not necessarily represent future cash requirements affecting our liquidity position.

Liquidity needs can be met from either assets or liabilities. On the asset side, our primary sources of liquidity include cash and due from banks, federal funds sold, available-for-sale investment securities and scheduled repayments and maturities of loans. We maintain adequate levels of cash and cash equivalents to meet our day-to-day needs. As of September 30, 2013, our cash and cash equivalents were $112.3 million, or 2.7% of total assets, compared to $231.9 million, or 5.5% of total assets, as of December 31, 2012. Our available for sale investment securities and federal funds sold were $850.3 million as of September 30, 2013 and $743.4 million as of December 31, 2012.

Our available for sale investment portfolio is comprised of approximately 65.4% or $548.7 million of securities which mature in less than five years. As of September 30, 2013 and December 31, 2012, $538.9 million and $532.8 million, respectively, of securities were pledged as collateral for various public fund deposits and securities sold under agreements to repurchase.

On the liability side, our principal sources of liquidity are deposits, borrowed funds, and access to capital markets. Customer deposits are our largest sources of funds. As of September 30, 2013, our total deposits were $3.25 billion, or 78.1% of total assets, compared to $3.48 billion, or 82.1% of total assets, as of December 31, 2012. We attract our deposits primarily from individuals, business, and municipalities located in our market areas.

We may occasionally use our Fed funds lines of credit in order to temporarily satisfy short-term liquidity needs. We have Fed funds lines with three other financial institutions pursuant to which we could have borrowed up to $35.0 million on an unsecured basis as of September 30, 2013 and December 31, 2012. These lines may be terminated by the respective lending institutions at any time.

We also maintain lines of credit with the Federal Home Loan Bank. Our FHLB borrowed funds were $270.2 million and $130.4 million at September 30, 2013 and December 31, 2012, respectively. At September 30, 2013, $170.0 million and $100.2 million of the outstanding balance were short-term and long-term advances, respectively. All of the outstanding balance at December 31, 2012 was long-term advances. Our FHLB borrowing capacity was $632.5 million and $640.5 million as of September 30, 2013 and December 31, 2012, respectively.

We believe that we have sufficient liquidity to satisfy our current operations.

Market Risk Management. Our primary component of market risk is interest rate volatility. Fluctuations in interest rates will ultimately impact both the level of income and expense recorded on a large portion of our assets and liabilities, and the market value of all interest-earning assets and interest-bearing liabilities, other than those which possess a short term to maturity. We do not hold market risk sensitive instruments for trading purposes.

Asset/Liability Management. Our management actively measures and manages interest rate risk. The asset/liability committees of the boards of directors of our holding company and bank subsidiary are also responsible for approving our asset/liability management policies, overseeing the formulation and implementation of strategies to improve balance sheet positioning and earnings, and reviewing our interest rate sensitivity position.

One of the tools that our management uses to measure short-term interest rate risk is a net interest income simulation model. This analysis calculates the difference between net interest income forecasted using base market rates and using a rising and a falling interest rate scenario. The income simulation model includes various assumptions regarding the re-pricing relationships for each of our products. Many of our assets are floating rate loans, which are assumed to re-price immediately, and proportional to the change in market rates, depending on their contracted index. Some loans and investments include the opportunity of prepayment (embedded options), and accordingly the simulation model uses indexes to estimate these prepayments and reinvest their proceeds at current yields. Our non-term deposit products re-price more slowly, usually changing less than the change in market rates and at our discretion.

This analysis indicates the impact of changes in net interest income for the given set of rate changes and assumptions. It assumes the balance sheet remains static and that its structure does not change over the course of the year. It does not account for all factors that impact this analysis, including changes by management to mitigate the impact of interest rate changes or secondary impacts such as changes to our credit risk profile as interest rates change.

Table of Contents

Furthermore, loan prepayment rate estimates and spread relationships change regularly. Interest rate changes create changes in actual loan prepayment rates that will differ from the market estimates incorporated in this analysis. Changes that vary significantly from the assumptions may have significant effects on our net interest income.

Interest Rate Sensitivity. Our primary business is banking and the resulting earnings, primarily net interest income, are susceptible to changes in market interest rates. It is management s goal to maximize net interest income within acceptable levels of interest rate and liquidity risks.

A key element in the financial performance of financial institutions is the level and type of interest rate risk assumed. The single most significant measure of interest rate risk is the relationship of the repricing periods of earning assets and interest-bearing liabilities. The more closely the repricing periods are correlated, the less interest rate risk we assume. We use repricing gap and simulation modeling as the primary methods in analyzing and managing interest rate risk.

Gap analysis attempts to capture the amounts and timing of balances exposed to changes in interest rates at a given point in time. Our gap position as of September 30, 2013 was asset sensitive with a one-year cumulative repricing gap of 1.3%. During these periods, the amount of change our asset base realizes in relation to the total change in market interest rate exceeds that of the liability base.

We have a portion of our securities portfolio invested in mortgage-backed securities. Mortgage-backed securities are included based on their final maturity date. Expected maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

Table 23 presents a summary of the repricing schedule of our interest-earning assets and interest-bearing liabilities (gap) as of September 30, 2013.

Table 23: Interest Rate Sensitivity

	Interest Rate Sensitivity Period							
	0-30 Days	**31-90 Days**	**91-180 Days**	**181-365 Days**	**1-2 Years**	**2-5 Years**	**Over 5 Years**	**Total**
	(Dollars in thousands)							
Earning assets								
Interest-bearing deposits due from banks	$ 35,080	$	$	$	$	$	$	$ 35,080
Federal funds sold	10,700							10,700
Investment securities	52,598	72,369	48,389	77,694	103,955	195,554	298,529	849,088
Loans receivable	463,599	220,906	325,392	483,636	518,627	542,500	93,502	2,648,162
Total earning assets	561,977	293,275	373,781	561,330	622,582	738,054	392,031	3,543,030

Interest-bearing liabilities								
Interest-bearing transaction and savings deposits	73,648	147,296	220,944	441,887	273,249	264,517	261,469	1,683,010
Time deposits	96,089	140,242	155,212	236,732	100,959	79,194	52	808,480
Federal funds purchased								
Securities sold under repurchase agreements	60,611				1,426	4,278	4,992	71,307
FHLB borrowed funds	170,106	13	19	137	5,283	59,263	35,411	270,232
Subordinated debentures	3,093							3,093
Total interest-bearing liabilities	403,547	287,551	376,175	678,756	380,917	407,252	301,924	2,836,122
Interest rate sensitivity gap	$ 158,430	$ 5,724	$ (2,394)	$ (117,426)	$ 241,665	$ 330,802	$ 90,107	$ 706,908
Cumulative interest rate sensitivity gap	$ 158,430	$ 164,154	$ 161,760	$ 44,334	$ 285,999	$ 616,801	$ 706,908	
Cumulative rate sensitive assets to rate sensitive liabilities	139.3%	123.8%	115.2%	102.5%	113.4%	124.3%	124.9%	
Cumulative gap as a % of total earning assets	4.5%	4.6%	4.6%	1.3%	8.1%	17.4%	20.0%	

86

Table of Contents

Item 4: CONTROLS AND PROCEDURES
Article I. Evaluation of Disclosure Controls

Based on their evaluation as of the end of the period covered by this Quarterly Report on Form 10-Q, the Chief Executive Officer and Chief Financial Officer have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. Additionally, our disclosure controls and procedures were also effective in ensuring that information required to be disclosed in our Exchange Act report is accumulated and communicated to our management, including the Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures.

Article II. Changes in Internal Control Over Financial Reporting

There have not been any changes in the Company s internal controls over financial reporting during the quarter ended September 30, 2013, which have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II: OTHER INFORMATION

Item 1: Legal Proceedings
There are no material pending legal proceedings, other than ordinary routine litigation incidental to its business, to which Home BancShares, Inc. or its subsidiaries are a party or of which any of their property is the subject.

Item 1A: Risk Factors
There were no material changes from the risk factors set forth in Part I, Item 1A, Risk Factors, of our Form 10-K for the year ended December 31, 2012. See the discussion of our risk factors in the Form 10-K, as filed with the SEC. The risks described are not the only risks facing the Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 2: Unregistered Sales of Equity Securities and Use of Proceeds
Not applicable.

Item 3: Defaults Upon Senior Securities
Not applicable.

Item 4: (Reserved)

Table of Contents

Item 5: Other Information
Not applicable.

Item 6: Exhibits

12.1	Computation of Ratios of Earnings to Fixed Charges*
15	Awareness of Independent Registered Public Accounting Firm*
31.1	CEO Certification Pursuant Rule 13a-14(a)/15d-14(a)*
31.2	CFO Certification Pursuant Rule 13a-14(a)/15d-14(a)*
32.1	CEO Certification Pursuant 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes Oxley Act of 2002*
32.2	CFO Certification Pursuant 18 U.S.C. Section 1350, as adopted pursuant to section 906 of the Sarbanes Oxley Act of 2002*
101.INS	XBRL Instance Document*
101.SCH	XBRL Taxonomy Extension Schema Document*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document*

* Filed herewith

Table of Contents

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.

HOME BANCSHARES, INC.

(Registrant)

Date: November 7, 2013	/s/ C. Randall Sims C. Randall Sims, Chief Executive Officer
Date: November 7, 2013	/s/ Randy E. Mayor Randy E. Mayor, Chief Financial Officer