CAPTION SHEET   CASE MANAGEMENT SYSTEM

1. REPORT DATE: 00/00/00
2. BUREAU: FUS
3. SECTION(S):
4. PUBLIC MEETING DATE: 00/00/00
5. APPROVED BY:
   DIRECTOR:
   SUPERVISOR:
6. PERSON IN CHARGE:
7. DATE FILED: 08/17/05
8. DOCKET NO: A-125142
9. EFFECTIVE DATE: 00/00/00

PARTY/COMPLAINANT:

RESPONDENT/APPLICANT: BP ENERGY COMPANY

COMP/APP COUNTY: UTILITY CODE: 125142

ALLEGATION OR SUBJECT

APPLICATION OF BP ENERGY COMPANY FOR APPORVAL TO OFFER RENDER, FURNISH OR SUPPLY NATURAL GAS SERVICES TO THE PUBLIC IN THE COMMONWEALTH OF PENNSYLVANIA AS A BROKER, MARKETER, AND AGGREGATOR ENGAGED IN THE BUSINESS OF SUPPLYING NATURAL GAS SERVICES, AND AS A SUPPLIER OF NATURAL GAS SERVICES.

DOCUMENT FOLDER

ORIGINAL

MWN

McNees Wallace & Nurick LLC

attorneys at law

SUSAN E. BRUCE
DIRECT DIAL: (717) 237-5254
E-MAIL ADDRESS: SBRUCE@MWN.COM

August 17, 2005

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

VIA HAND DELIVERY

A-125142

RE: **Application of BP Energy Company for Approval To Offer, Render, Furnish, or Supply Natural Gas Supply Services to the Public in the Commonwealth of Pennsylvania; Docket No. __________**

Dear Secretary McNulty:

Please find enclosed for filing with the Commission an original and eight (8) copies of the Application of BP Energy Company for a Gas Supplier License as captioned above. Also enclosed is an electronic version of the filing and a check in the amount of $350.00 in the nature of an application fee.

As evidenced by the attached Certificate of Service, all parties to this proceeding are being duly served. Please date stamp the extra copy of this transmittal letter and kindly return it to our messenger for our filing purposes.

Very truly yours,

McNEES WALLACE & NURICK LLC

DOCUMENT FOLDER

By Susan E. Bruce
Susan E. Bruce

Counsel to BP Energy Company

SEB:mas
Enclosures
c: Certificate of Service

30

RECEIVED
2005 AUG 17 PM 3:
SECRETARY'S BUREAU

ORIGINAL

CERTIFICATE OF SERVICE

A-125142

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA FIRST-CLASS MAIL

Irwin A. Popowsky, Esq.
Office of Consumer Advocate
Forum Place, 5th Floor
555 Walnut Street
Harrisburg, PA 17101-1923

William R. Lloyd, Jr., Esq.
Office of Small Business Advocate
Commerce Building, Suite 1102
300 North Second Street
Harrisburg, PA 17101

Office of the Attorney General
Bureau of Consumer Protection
Strawberry Square, 14th Floor
Harrisburg, PA 17120

Commonwealth of Pennsylvania
Department of Revenue
Bureau of Compliance
Harrisburg, PA 17128-0946

Mr. Mike Vogel
NUI Valley Cities Gas
P. O. Box 3175
Union, NJ 07083-1975

Mr. Jim Evans
Mr. Tom Olsen
Penn Fuel
2 North 9th Street
GENA94
Allentown, PA 18101

Mr. Robert M. Hovanec
T. W. Phillips Gas and Oil Company
205 North Main Street
Butler, PA 16001

Mr. Richard N. Marshall
Ms. Wendy K. Saxe
PG Energy
One PEI Center
Wilkes-Barre, PA 18711-0601

Mr. Donald A. Melzer
Carnegie Natural Gas Company
800 Regis Avenue
Pittsburgh, PA 19236

Mr. Eric Burgis
Philadelphia Gas Works
800 West Montgomery Avenue
Philadelphia, PA 19122

Mr. Paul R. Mundy
National Fuel Gas Distribution Corp.
10 Lafayette Square
Buffalo, NY 14203

Mr. Joe Gregorini
Mr. Bill McKeown
The Peoples Natural Gas Company
625 Liberty Avenue
Pittsburgh, PA 15222

Mr. David Beaston
Mr. Bob Krieger
UGI
225 Morgantown Road
P. O. Box 12677
Reading, PA 15222

Ms. Antionette Litchy
Equitable Gas Company
200 Allegheny Center Mall
Pittsburgh, PA 15212-5352

Certificate of Service
Page 2

Mr. Erich Evans
Ms. Heather Bauer
Columbia Gas of PA, Inc.
200 Civic Center Drive
Columbus, OH 43215

Mr. Kevin Carrabine
PECO
300 Front Street Building 2
Conshohocken, PA 19428

Susan E. Bruce

Dated this 17th day of August, 2005, in Harrisburg, Pennsylvania.

ORIGINAL

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of BP ENERGY COMPANY for approval to offer, render, furnish, or as a(n) natural gas supplier to the public in the Commonwealth of Pennsylvania.

To the Pennsylvania Public Utility Commission: A-125142

1. **IDENTITY OF THE APPLICANT:** The name, address, telephone number, and FAX number of the Applicant are:

BP ENERGY COMPANY
501 Westlake Park Boulevard
Houston, TX 77079
Tele: 281-366-5009
Fax: 281-366-2200

Please identify any predecessor(s) of the Applicant and provide other names under which the Applicant has operated within the preceding five (5) years, including name, address, and telephone number.

Formerly known as:
Amoco Energy Trading Corporation
501 Westlake Park Boulevard
Houston, TX 77079
Tele: 281-366-5009
Fax: 281-366-2200

RECEIVED
AUG 17 2005
PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

2. a. **CONTACT PERSON:** The name, title, address, telephone number, and FAX number of the person to whom questions about this Application should be addressed are:

Michelle Voinorosky
Attorney
BP Energy Company
501 Westlake Park Boulevard
Houston, TX 77079
Tele: 281-366-6210
Fax: 281-366-7583

Susan E. Bruce
McNees Wallace & Nurick LLC
P.O. Box 1166
100 Pine Street
Harrisburg, PA 17108-1166
Tele: 717-237-5254
Fax: 717-237-5300

b. **CONTACT PERSON-PENNSYLVANIA EMERGENCY MANAGEMENT AGENCY:** The name, title, address telephone number and FAX number of the person with whom contact should be made by PEMA:

Mark Hanson
Manager, Mid-Atlantic Marketing & Origination
BP Energy Company
501 Westlake Park Boulevard
Houston, Texas 77079
Phone: 281-366-3321
Fax: 281-366-4929

DOCUMENT
FOLDER

3.a. **ATTORNEY:** If applicable, the name, address, telephone number, and FAX number of the Applicant's attorney are:

Justin Stuhldreher
Managing Attorney
BP Energy Company
501 Westlake Park Boulevard
Houston, TX 77079
Tele: 281-366-2568
Fax: 281-366-7583

DOCKETED
AUG 25 2005

b. **REGISTERED AGENT**: If the Applicant does not maintain a principal office in the Commonwealth, the required name, address, telephone number and FAX number of the Applicant's Registered Agent in the Commonwealth are:

CT Corporation System
1515 Market Street, Suite 1210
Philadelphia, PA 19102
Tele: 215-563-7750
Fax: (does not accept faxed lawsuits)

4. **FICTITIOUS NAME:** (select and complete appropriate statement)

☐ The Applicant will be using a fictitious name or doing business as ("d/b/a"):

Attach to the Application a copy of the Applicant's filing with the Commonwealth's Department of State pursuant to 54 Pa. C.S. §311, Form PA-953.

or

☑ The Applicant will not be using a fictitious name.

5. **BUSINESS ENTITY AND DEPARTMENT OF STATE FILINGS:** (select and complete appropriate statement)

☐ The Applicant is a sole proprietor.

If the Applicant is located outside the Commonwealth, provide proof of compliance with 15 Pa. C.S. §4124 relating to Department of State filing requirements.

or

☐ The Applicant is a:

☐ domestic general partnership (*)
☐ domestic limited partnership (15 Pa. C.S. §8511)
☐ foreign general or limited partnership (15 Pa. C.S. §4124)
☐ domestic limited liability partnership (15 Pa. C.S. §8201)
☐ foreign limited liability general partnership (15 Pa. C.S. §8211)
☐ foreign limited liability limited partnership (15 Pa. C.S. §8211)

Provide proof of compliance with appropriate Department of State filing requirements as indicated above.

Give name, d/b/a, and address of partners. If any partner is not an individual, identify the business nature of the partner entity and identify its partners or officers.

☐ * If a corporate partner in the Applicant's domestic partnership is not domiciled in Pennsylvania, attach a copy of the Applicant's Department of State filing pursuant to 15 Pa. C.S. §4124.

or

☑ The Applicant is a:

☐ domestic corporation (none)

- ☑ foreign corporation (15 Pa. C.S. §4124)
- ☐ domestic limited liability company (15 Pa. C.S. §8913)
- ☐ foreign limited liability company (15 Pa. C.S. §8981)
- ☐ Other ______________________________

Provide proof of compliance with appropriate Department of State filing requirements as indicated above.

See Exhibit A attached hereto and made a part hereof for all purposes.

Additionally, provide a copy of the Applicant's Articles of Incorporation.

See Exhibit B attached hereto and made a part hereof for all purposes.

Give name and address of officers.

See Exhibit C attached hereto and made a part hereof for all purposes.

The Applicant is incorporated in the state of Delaware.

6. **AFFILIATES AND PREDECESSORS WITHIN PENNSYLVANIA:** (select and complete appropriate statement)

☑ Affiliate(s) of the Applicant doing business in Pennsylvania are:

See Exhibit D attached hereto and made a part hereof for all purposes.

Give name and address of the affiliate(s) and state whether the affiliate(s) are jurisdictional public utilities.

See Exhibit D attached hereto and made a part hereof for all purposes.

☑ Does the Applicant have any affiliation with or ownership interest in:
- (a) any other Pennsylvania retail natural gas supplier licensee or licensee applicant,
- (b) any other Pennsylvania retail licensed electric generation supplier or license applicant,
- (c) any Pennsylvania natural gas producer and/or marketer,
- (d) any natural gas wells or
- (e) any local distribution companies (LDCs) in the Commonwealth

If the response to parts a, b, c, or d above is affirmative, provide a detailed description and explanation of the affiliation and/or ownership interest.

Applicant's affiliate, BP Canada Energy Marketing Corp., is (or has been) engaged in the sale of natural gas and supply services to local distribution companies ("LDCs"), marketers/aggregators, and industrial and commercial customers at the citygate in Pennsylvania and other US States.

Applicant and BP Canada Energy Marketing Corp. are both wholly owned indirect subsidiaries of BP America Inc. (See Exhibit E attached hereto and made a part hereof for all purposes.)

☑ Provide specific details concerning the affiliation and/or ownership interests involving:
- (a) any natural gas producer and/or marketers,
- (b) any wholesale or retail supplier or marketer of natural gas, electricity, oil, propane or other energy sources.

BP produces approximately 3.1 Bcf/d of natural gas throughout North America. BP Energy Company and its affiliates BP Canada Energy Marketing Corp. and IGI Resources Inc. market this production and purchase natural gas from other third parties to meet the supply and demand needs of customers throughout North

America. Customers include other marketers, aggregators, local distribution companies, industrial, commercial and governmental entities. Neither Applicant nor any of its affiliates are engaged in the sale of natural gas to residential customers.

Applicant and its affiliates BP Canada Energy Marketing Corp. and IGI Resources Inc. are wholly owned indirect subsidiaries of BP America Inc. (See Exhibit E attached hereto and made a part hereof for all purposes.) IGI Resources Inc. conducts business primarily in the Pacific Northwest region of the U.S. BP Canada Energy Marketing Corp. conducts business throughout the United States generally and in the Mid-Continent primarily.

BP Products North America Inc. markets other energy products throughout the United States. (See Exhibit E.)

☑ Provide the Pa PUC Docket Number if the applicant has ever applied:
   (a) for a Pennsylvania Natural Gas Supplier license, or
   (b) for a Pennsylvania Electric Generation Supplier license.

PUC Docket Number: A-110144 for Electric Generation Supplier License

☑ If the Applicant or an affiliate has a predecessor who has done business within Pennsylvania, give name and address of the predecessor(s) and state whether the predecessor(s) were jurisdictional public utilities.

Amoco Energy Trading Corporation changed its name to BP Energy Company effective August 22, 2000. The address is the same as that listed above for BP Energy Company.

Amoco Canada Marketing Corp. changed its name to BP Canada Energy Marketing Corp. effective August 14, 2000. Address: 4101 Winfield Road, Warrenville, Illinois 60555

Neither was a jurisdictional public utility.

or

☐ The Applicant has no affiliates doing business in Pennsylvania or predecessors which have done business in Pennsylvania.

7. **APPLICANT'S PRESENT OPERATIONS:** (select and complete the appropriate statement)

☐ The Applicant is presently doing business in Pennsylvania as a

- ☐ natural gas interstate pipeline.
- ☐ municipal providing service outside its municipal limits.
- ☐ local gas distribution company
- ☐ retail supplier of natural gas services in the Commonwealth
- ☐ a natural gas producer
- ☑ Other. (Identify the nature of service being rendered.)

Applicant is presently doing business in Pennsylvania as a licensed Electric Generation Supplier, wholesale marketer of natural gas and marketer of natural gas services to large industrial customers at citygates (without utilizing the jurisdictional facilities of natural gas distribution companies).

or

☐ The Applicant is not presently doing business in Pennsylvania.

8. **APPLICANT'S PROPOSED OPERATIONS:** The Applicant proposes to operate as a:

- ☑ supplier of natural gas services.
- ☐ Municipal supplier of natural gas services.
- ☐ Cooperative supplier of natural gas services.
- ☑ Broker/Marketer engaged in the business of supplying natural gas services.
- ☑ *Aggregator engaged in the business of supplying natural gas services.*
- ☐ Other (Describe):

9. **PROPOSED SERVICES:** Generally describe the natural gas services which the Applicant proposes to offer.

By this Application, BP Energy proposes to expand its range of services to market natural gas and supply services to large commercial, industrial and governmental retail gas customers.

Applicant will not be engaging in the sale of natural gas to residential customers.

10. **SERVICE AREA:** Generally describe the geographic area in which Applicant proposes to offer services.

Applicant proposes to offer natural gas services in all geographic areas of Pennsylvania.

11. **CUSTOMERS:** Applicant proposes to initially provide services to:

- ☐ Residential Customers
- ☐ Commercial Customers - (Less than 6,000 Mcf annually)
- ☑ Commercial Customers - (6,000 Mcf or more annually)
- ☑ Industrial Customers
- ☑ Governmental Customers
- ☐ All of above
- ☐ Other (Describe):

12. START DATE: The Applicant proposes to begin delivering services upon receipt of its Natural Gas Supplier license from the Pennsylvania Public Utility Commission.

13. **NOTICE:** Pursuant to Section 5.14 of the Commission's Regulations, 52 Pa. Code §5.14, serve a copy of the signed and verified Application with attachments on the following:

Irwin A. Popowsky
Office of Consumer Advocate
5th Floor, Forum Place
555 Walnut Street
Harrisburg, PA 17120-1921

Office of the Attorney General
Bureau of Consumer Protection
Strawberry Square, 14th Floor
Harrisburg, PA 17120

William R. Lloyd, Jr.
Commerce Building, Suite 1102
Small Business Advocate
300 North Second Street
Harrisburg, PA 17101

Commonwealth of Pennsylvania
Department of Revenue
Bureau of Compliance
Harrisburg, PA 17128-0946

Any of the following Natural Gas Distribution Companies through whose transmission and distribution facilities the applicant intends to supply customers:

NUI Valley Cities Gas (NUI Transportation Services) Mike Vogel PO Box 3175 Union, NJ 07083-1975 PH: 908.289.5000 ext. 5441 FAX: 908.2898.6444	**National Fuel Gas Distribution Corp.** Paul R. Mundy 10 Lafayette Square Buffalo, NY 14203 PH: 716.857.7756 FAX: 716.857.7479 e-mail: mundyp@natfuel.com
Penn Fuel [North Penn Gas Company & Penn Fuel Gas] Jim Evans or Tom Olsen 2 North 9th Street GENA94 Allentown, PA 18101 PH: 610.774.7981 610.774.4975 FAX: 610.774.5694 610.774.4975 e-mail: jevans@papl.com or teolson@papl.com	**The Peoples Natural Gas Company** Joe Gregorini or Bill McKeown 625 Liberty Avenue Pittsburgh, PA 15222 e-mail: jgregorini@png.cng.com PH: 412.497.6851 or 412.497.6840 FAX: 412.497.6630
T. W. Phillips Gas and Oil Company Robert M. Hovanec 205 North Main Street Butler, PA 16001 PH: 724.287.2725 FAX: 724.287.5021 e-mail: rhovanec@twphillips.com	**UGI** David Beaston or Bob Krieger PO Box 12677 or 225 Morgantown Rd Reading, PA 15222 Reading, PA 15222 PH: 610.796.3425 PH: 610.796.3516 FAX: 610.796.3559
PG Energy Richard N. Marshall or Wendy K. Saxe One PEI Center Wilkes-Barre, PA 18711-0601 e-mail: marshall@pgenergy.com or saxe@pgenergy.com PH: 570.829.8795 FAX: 570.829.8652	**Equitable Gas Company** Antionette Litchy 200 Allegheny Center Mall Pittsburgh, PA 15212-5352 PH: 412.395.3117 FAX: 412.395.3156
Carnegie Natural Gas Company Donald A. Melzer 800 Regis Avenue Pittsburgh, PA 19236 PH: 412.655.8510 ext. 331 FAX: 412.655.0335	**Columbia Gas of PA, Inc.** Erich Evans or Heather Bauer 200 Civic Center Drive Columbus, OH 43215 PH: 614.460.6254 or 614.460.5554 FAX: 614.460.4291
Philadelphia Gas Works Eric Burgis 800 West Montgomery Avenue Philadelphia, PA 19122 email: eric.burgis@pgworks.com PH: 215.684.6907 FAX: 215.684.6564	**PECO** Kevin Carrabine 300 Front Street Building 2 Conshohocken, PA 19428 PH: 610.832.6413

Pursuant to Sections 1.57 and 1.58 of the Commission's Regulations, 52 Pa. Code §§1.57 and 1.58, attach Proof of Service of the Application and attachments upon the above named parties. Upon review of the Application, further notice may be required pursuant to Section 5.14 of the Commission's Regulations, 52 Pa. Code §5.14.

14. **TAXATION:** Complete the TAX CERTIFICATION STATEMENT attached as Appendix B to this application.

A completed Tax Certification Statement is attached hereto at Exhibit F.

15. **COMPLIANCE:** State specifically whether the Applicant, an affiliate, a predecessor of either, or a person identified in this Application has been convicted of a crime involving fraud or similar activity. Identify all proceedings, by name, subject and citation, dealing with business operations, in the last five (5) years, whether before an administrative body or in a judicial forum, in which the Applicant, an affiliate, a predecessor of either, or a person identified herein has been a defendant or a respondent. Provide a statement as to the resolution or present status of any such proceedings.

Neither the Applicant, its affiliates that market natural gas (BP Canada Energy Marketing Corp. and IGI Resources, Inc.), mnor any person identified in this Application has been convicted of a crime involving fraud or similar activity.

For a list of applicable proceedings involving Applicant and its U.S. natural gas marketing affiliates (BP Canada Energy Marketing Corp. and IGI Resources, Inc.), see Exhibit G attached hereto and made a part hereof for all purposes.

16. **STANDARDS, BILLING PRACTICES, TERMS AND CONDITIONS OF PROVIDING SERVICE AND CONSUMER EDUCATION:** All services should be priced in clearly stated terms to the extent possible. Common definitions should be used. All consumer contracts or sales agreements should be written in plain language with any exclusions, exceptions, add-ons, package offers, limited time offers or other deadlines prominently communicated. Penalties and procedures for ending contracts should be clearly communicated.

a. Contacts for Consumer Service and Complaints: Provide the name, title, address, telephone number and FAX number of the person and an alternate person responsible for addressing customer complaints. These persons will ordinarily be the initial point(s) of contact for resolving complaints filed with Applicant, the Distribution Company, the Pennsylvania Public Utility Commission or other agencies.

Mark Hanson
Manager, Mid-Atlantic Marketing & Origination
BP Energy Company
501 Westlake Park Boulevard
Houston, Texas 77079
Phone: 281-366-3321
Fax: 281-366-4929

b. Provide a copy of all standard forms or contracts that you use, or propose to use, for service provided to residential customers.

Not applicable – Applicant does not plan to provide service to residential customers.

c. If proposing to serve Residential and/or Small Commercial customers, provide a disclosure statement. A sample disclosure statement is provided as Appendix B to this Application.

Not applicable – Applicant does not plan to provide service to residential customers or small-volume commercial customers.

17. **FINANCIAL FITNESS:**

A. Applicant shall provide sufficient information to demonstrate financial fitness commensurate with the service proposed to be provided. Examples of such information which may be submitted include the following:

- Actual (or proposed) organizational structure including parent, affiliated or subsidiary companies.
- Published parent company financial and credit information.

- Applicant's balance sheet and income statement for the most recent fiscal year. Published financial information such as 10K's and 10Q's may be provided, if available.

- Evidence of Applicant's credit rating. Applicant may provide a copy of its Dun and Bradstreet Credit Report and Robert Morris and Associates financial form or other independent financial service reports.

- A description of the types and amounts of insurance carried by Applicant which are specifically intended to provide for or support its financial fitness to perform its obligations as a licensee.

- Audited financial statements

- Such other information that demonstrates Applicant's financial fitness.

<u>See Exhibit H attached hereto and made a part hereof for all purposes.</u>

B. Applicant must provide the following information:

- Identify Applicant's chief officers including names and their professional resumes.

- Provide the name, title, address, telephone number and FAX number of Applicant's custodian for its accounting records.

<u>See Exhibit I attached hereto and made a part hereof for all purposes.</u>

18. **TECHNICAL FITNESS:** To ensure that the present quality and availability of service provided by natural gas utilities does not deteriorate, the Applicant shall provide sufficient information to demonstrate technical fitness commensurate with the service proposed to be provided. Examples of such information which may be submitted include the following:

- The identity of the Applicant's officers directly responsible for operations, including names and their professional resumes.

- A copy of any Federal energy license currently held by the Applicant.

- Proposed staffing and employee training commitments.

- Business plans.

<u>See Exhibit J attached hereto and made a part hereof for all purposes.</u>

19. **TRANSFER OF LICENSE:** The Applicant understands that if it plans to transfer its license to another entity, it is required to request authority from the Commission for permission prior to transferring the license. See 66 Pa. C.S. Section 2208(D). Transferee will be required to file the appropriate licensing application.

20. **UNIFORM STANDARDS OF CONDUCT AND DISCLOSURE:** As a condition of receiving a license, Applicant agrees to conform to any Uniform Standards of Conduct and Disclosure as set forth by the Commission.

21. **REPORTING REQUIREMENTS**: Applicant agrees to provide the following information to the Commission or the Department of Revenue, as appropriate:

a. Reports of Gross Receipts: Applicant shall report its Pennsylvania intrastate gross receipts to the Commission on an annual basis no later than 30 days following the end of the calendar year.

Applicant will be required to meet periodic reporting requirements as may be issued by the Commission to fulfill the Commission's duty under Chapter 22 pertaining to reliability and to inform the Governor and Legislature of the progress of the transition to a fully competitive natural gas market.

22. **FURTHER DEVELOPMENTS:** Applicant is under a continuing obligation to amend its application if substantial changes occur in the information upon which the Commission relied in approving the original filing.

23. **FALSIFICATION:** The Applicant understands that the making of false statement(s) herein may be grounds for denying the Application or, if later discovered, for revoking any authority granted pursuant to the Application. This Application is subject to 18 Pa. C.S. §§4903 and 4904, relating to perjury and falsification in official matters.

24. **FEE:** The Applicant has enclosed the required initial licensing fee of $350.00 payable to the Commonwealth of Pennsylvania.

Applicant: BP ENERGY COMPANY

By: O. Alvarez

Name: Orlando A. Alvarez

Title: Vice President

MA

Exhibit Index

Exhibit A	Certificate of Authority
Exhibit B	Articles of Incorporation and Name Change
Exhibit C	Officers
Exhibit D	Affiliates
Exhibit E	Corporate Organizational Charts
Exhibit F	Tax Certification Statement
Exhibit G	List and Status of Applicable Proceedings
Exhibit H	Financial Fitness
Exhibit I	Chief Officers and Resumes
Exhibit J	Technical Fitness
Exhibit K	Affidavits
Exhibit L	Certificate of Service

COMMONWEALTH OF PENNSYLVANIA

DEPARTMENT OF STATE

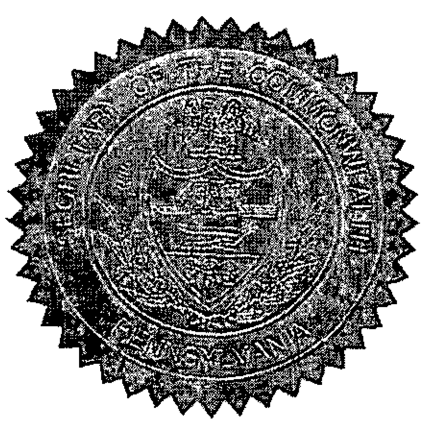
July 20, 2005

TO ALL WHOM THESE PRESENTS SHALL COME, GREETING:

BP ENERGY COMPANY

I, Pedro A. Cortés, Secretary of the Commonwealth of Pennsylvania do hereby certify that the foregoing and annexed is a true and correct photocopy of Certificate of Authority and all Amendments

which appear of record in this department



IN TESTIMONY WHEREOF, I have hereunto set my hand and caused the Seal of the Secretary's Office to be affixed, the day and year above written.

Pedro A. Cortés

Secretary of the Commonwealth

STMARTZ

9155- 643

Microfilm Number ____________

Entity Number 2047284

Filed with the Department of State on AUG 30 1991

Robert A. Grant

Deputy Secretary of the Commonwealth

APPLICATION FOR CERTIFICATE OF AUTHORITY

DSCB:15-4124 (Rev 90)

Indicate type of corporation (check one):

✓ Foreign Business Corporation

__ Foreign Nonprofit Corporation (15 Pa. C.S. § 6124)

__ Foreign Professional Corporation

1. The name of the corporation is: Amoco Energy Trading Corporation

2. The name which the corporation adopts for use in this Commonwealth is (complete only when the corporation must adopt a corporate designator for use in Pennsylvania):

   N/A

3. (Complete only when the corporation name is not available for use in Pennsylvania): N/A

   __ Limited Certificate of Authority only:

   This is a Limited Certificate of Authority for the sole purpose of qualifying to register the fictitious name of:

   ____

   This corporation shall do business in Pennsylvania only under such fictitious name pursuant to the attached resolution by the board of directors under 15 Pa. C.S. § 41[illegible](b)(1). (See attached fictitious name form DSCB:54-311).

4. The address of this corporation's initial (a) registered office in this Commonwealth or (b) commercial registered office provider and the county of venue is:

   (a) c/o C T CORPORATION SYSTEM, 1635 Market Street, Philadelphia, Pa. 19103, Philadelphia
   Number and Street — City — State — Zip — County

   (b) N/A
   Name of Commercial Registered Office Provider — County

   For a corporation represented by a commercial registered office provider, the county in (b) shall be deemed the county in which the corporation is located for venue and official publication purposes.

5. The corporation is incorporated for a purpose ~~(not)~~ involving pecuniary profit, incidental or otherwise to its shareholders. (Strike out if not applicable):

9155- 649

DSCB:15-4124 (Rev 89)-2

6. The name of the jurisdiction under the laws of which the corporation is incorporated is:

Delaware

7. The address of its principal office under the laws of the jurisdiction in which it is incorporated is:
c/o The Corporation Trust Company, Corporation Trust, 1209 Orange street,

Wilmington, Delaware 19801

IN TESTIMONY WHEREOF, the undersigned corporation has caused this application to be signed by a duly authorized officer this 8th day of August, 19 91.

Amoco Energy Trading Corporation
(Name of Corporation)

BY: [signature]
(Signature)

TITLE: President

91 AUG ... 2:37

(PA - 974)

NOV 15 2000

Microfilm Number 200086 - 46

Entity Number 2047284

Filed with the Department of State on

Secretary of the Commonwealth JK

APPLICATION FOR AN AMENDED CERTIFICATE OF AUTHORITY
FOREIGN CORPORATION
DSCB:15-4126/6126 (Rev 90)

Indicate type of corporation (check one):

X Foreign Business Corporation (15 Pa.C.S. § 4126)

___Foreign Nonprofit Corporation (15 Pa.C.S. § 6126)

In compliance with the requirements of the applicable provisions of 15 Pa.C.S. (relating to corporations and unincorporated associations) the undersigned foreign corporation, desiring to receive an amended certificate of authority hereby states that:

1. The name under which the corporation currently holds a certificate of authority to do business within the Commonwealth of Pennsylvania is: Amoco Energy Trading Corporation

2. The name of the jurisdiction under the laws of which the corporation is incorporated is: Delaware

3. The address of its principal office under the laws of the jurisdiction in which it is incorporated is:

1209 Orange Street, Wilmington, Delaware 19801, New Castle
Number and Street City State Zip County

4. The (a) address of this corporation's current registered office in this Commonwealth or (b) name of its commercial registered office provider and the county of venue is:

(a) ____
Number and Street City State Zip County

(b) c/o: C T Corporation System Philadelphia County
Name of Commercial Registered Office Provider County

For a corporation represented by a commercial registered office provider, the county in (b) shall be deemed the county in which the corporation is located for venue and official publication purposes.

(Check if applicable):

___ The foregoing reflects a change in Pennsylvania registered office.

5. The corporation desires that its certificate of authority be amended to change the name under which it is authorized to transact business in the Commonwealth of Pennsylvania to:

BP Energy Company

200086 - 47

DSCB:15-4126/6126 (Rev 90)-2

6. (If the name set forth in Paragraph 5 is not available for use in this Commonwealth, complete the following):

The fictitious name which the corporation adopts for use in transacting business in this Commonwealth is:

____

This corporation shall do business in Pennsylvania only under such fictitious name pursuant to the attached resolution of the board of directors in compliance with the requirements of the applicable provisions of 15 Pa.C.S (relating to corporations and unincorporated associations) and the attached form DSCB:54-311 (Application for Registration of Fictitious Name).

7 (Check one of the following as applicable):

_x_ The change of name reflects a change effected in the jurisdiction of incorporation.

___ Documents complying with the applicable provisions of 15 Pa.C.S. § 4123(b) or 6123(b) (relating to exception; name) accompany this application.

IN TESTIMONY WHEREOF, the undersigned corporation has caused this Application for an Amended Certificate of Authority to be signed by a duly authorized officer this 25 day of October 2000

BP Energy Company
(Name of Corporation)

BY: [signature]
(Signature)

TITLE: F. T. Kolb Assistant Secretary

State of Delaware

Office of the Secretary of State

I, EDWARD J. FREEL, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF AMENDMENT OF "AMOCO ENERGY TRADING CORPORATION", CHANGING ITS NAME FROM "AMOCO ENERGY TRADING CORPORATION" TO "BP ENERGY COMPANY", FILED IN THIS OFFICE ON THE TWENTY-SECOND DAY OF AUGUST, A.D. 2000, AT 4:30 O'CLOCK P.M.

A FILED COPY OF THIS CERTIFICATE HAS BEEN FORWARDED TO THE NEW CASTLE COUNTY RECORDER OF DEEDS.

Edward J. Freel, Secretary of State

2076758 8100

001425714

AUTHENTICATION: 0633914

DATE: 08-23-00

CERTIFICATE OF AMENDMENT

OF

CERTIFICATE OF INCORPORATION

AMOCO ENERGY TRADING CORPORATION, a corporation organized and existing under and by virtue of the General Corporation Law of the State of Delaware, DOES HEREBY CERTIFY:

FIRST: That the Board of Directors, by the unanimous written consent of its members, filed with the minutes of the Board, duly adopted a resolution setting forth a proposed amendment to the Certificate of Incorporation of said corporation, declaring said amendment to be advisable and calling a meeting of the stockholders of said corporation for consideration thereof. The resolution setting forth the proposed amendment is as follows:

> RESOLVED, that the Certificate of Incorporation of this corporation be amended by changing the Article thereof numbered FIRST so that, as amended, said Article shall be and read as follows:
>
> FIRST: The name of the corporation is BP ENERGY COMPANY.

SECOND: That thereafter, pursuant to resolution of its Board of Directors, in lieu of a meeting and vote of stockholders, the stockholders have given unanimous written consent to said amendment in accordance with Section 228 of the General Corporation Law of the State of Delaware.

THIRD: That said amendment was duly adopted in accordance with the provisions of Sections 242 and 228 of the General Corporation Law of the State of Delaware.

FOURTH: That the capital of said corporation shall not be reduced under or by reason of said amendment.

FIFTH: That this amendment to the Certificate of Incorporation will be effective on the date it is filed with the Secretary of State.

IN WITNESS WHEREOF, said AMOCO ENERGY TRADING CORPORATION has caused its corporate seal to be hereunto affixed and this certificate to be signed by Tony Fountain, its President, and attested to by F. T. Kolb, its Assistant Secretary, this 21st day of August, 2000.

BY: Tony Fountain
Tony Fountain, President

ATTEST:

F. T. Kolb
F. T. Kolb, Assistant Secretary

STATE OF TEXAS)
) ss.
COUNTY OF HARRIS)

The undersigned, a Notary Public, do hereby certify that TONY FOUNTAIN and F. T. KOLB of the above named AMOCO ENERGY TRADING CORPORATION, personally known to me to be the same persons whose names are subscribed to the foregoing instrument as President and Assistant Secretary, respectively, appeared before me this day in person, and acknowledged that they signed, sealed and delivered the said instrument as the free and voluntary act of said AMOCO ENERGY TRADING CORPORATION, and as their own free and voluntary act as President and Assistant Secretary, respectively, for the uses and purposes therein set forth.

GIVEN under my hand and official seal this 21st day of August, 2000.

DENISE ROBERTSON
Notary Public, State of Texas
My Commission Expires
October 12, 2004

Denise Robertson
Notary Public

State of Delaware

BOOK 0307 PAGE 405

Office of Secretary of State

I, MICHAEL HARKINS, SECRETARY OF STATE OF THE STATE OF DELAWARE DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF INCORPORATION OF AMOCO ENERGY TRADING CORPORATION FILED IN THIS OFFICE ON THE TWENTY-SIXTH DAY OF NOVEMBER, A.D. 1985, AT 12 O'CLOCK P.M.

! ! ! ! ! ! ! ! ! !

Michael Harkins, Secretary of State

AUTHENTICATION: 10668795

735330027

DATE: 11/26/1985

20767-58

7353300027

12:00 noon

CERTIFICATE OF INCORPORATION

OF

AMOCO ENERGY TRADING CORPORATION

1. The name of the corporation is:

AMOCO ENERGY TRADING CORPORATION

2. The address of its registered office in the State of Delaware is Corporation Trust Center, 1209 Orange Street, in the City of Wilmington, County of New Castle. The name of its registered agent at such address is The Corporation Trust Company.

3. The nature of the business or purposes to be conducted or promoted is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of Delaware.

4. The total number of shares of stock which the corporation shall have authority to issue is One Thousand (1,000) all of such shares shall be without par value.

5. The board of directors is authorized to make, alter or repeal the by-laws of the corporation. Election of directors need not be by written ballot.

6. The name and mailing address of the incorporator is:

L. M. Custis
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware 19801

I, THE UNDERSIGNED, being the incorporator hereinbefore named, for the purpose of forming a corporation pursuant to the General Corporation Law of Delaware, do make this certificate, hereby declaring and certifying that this is my act and deed and the facts herein stated are true, and accordingly have hereunto set my hand this 26th day of November, 1985.

L. M. Custis
L. M. Custis

RECEIVED FOR RECORD

NOV 26 1985

LEO J. DUGAN, Jr., Recorder

AMOCO ENERGY TRADING CORPORATION

Unanimous Waiver of Notice of Meeting

and Consent to the Adoption of Resolutions

November 26, 1985

The undersigned, being all of the directors of AMOCO ENERGY TRADING CORPORATION (the "Company"), hereby waive call, notice of meeting, formal meeting and vote, and do hereby consent to, confirm and ratify the adoption of the following corporate actions pursuant to Section 141(f) of the General Corporation Laws of the State of Delaware.

* * * * * *

RESOLVED: That the copy of the Certificate of Incorporation attached hereto as Exhibit A is the Certificate of Incorporation of the Company as filed and recorded in the State of Delaware on November 26, 1985; and further

RESOLVED: That the By-laws attached hereto as Exhibit B be, and they hereby are, adopted and in all respects approved as and for the By-laws of the Company; and further

RESOLVED: That the proposed form of stock certificate representing shares of Common Stock of the Company, without par value per share, attached hereto as Exhibit C, be, and it hereby is, approved as the form of certificate to represent fully-paid shares of the Common Stock of the Company; and further

RESOLVED: That the form of seal, an impression of which appears to the right hereof, be, and it hereby is, adopted as and for the seal of the Company; and further

RESOLVED: That the fiscal year of the Company be the calendar year; and further

RESOLVED: That the books of the Company be kept at the headquarter offices of the Company (presently located at 200 East Randolph Drive, Chicago, Illinois 60601); and further

RESOLVED: That the President, Vice President, and Treasurer of the Company are each hereby authorized acting individually:

1. To designate any bank or banks as depository for funds of the Company;

2. To execute powers of attorney or other suitable documents authorizing officers, employees, or other agents of the Company to deposit funds in bank accounts as established, and to make withdrawals upon checks manually signed;

3. To designate the person or persons upon whose facsimile signature the respective depository banks of the Company shall honor checks drawn against accounts so established, and to change such designation from time to time; and

4. To authorize the said banks to honor and charge the Company's account for all checks on which the actual or purported facsimile signature resembles the specimen duly filed with the banks regardless of by whom or by what means such facsimile signature may have been affixed thereto.

RESOLVED: That the Company forthwith issue 100 shares of no par value per share Common Stock to Amoco Production Company, a Delaware corporation ("Amoco"), upon payment therefor to the Company of the sum of $1,000.00, such sum to be deposited the Company's bank account; and further

RESOLVED: That the proper officers of the Company are hereby authorized to determine the times at which and manner in which funds are to be made available under the preceding resolution;

RESOLVED: That the Company hereby appoints The Corporation Trust Company, as the Company's registered agent for receiving service of process in the State of Delaware.

RESOLVED: That the following individuals are hereby elected to the offices set opposite their respective names, to serve in said offices until their successors shall have been duly elected and shall have qualified:

President	H. M. Hawkins
Vice President	R. K. Stehn
Vice President	R. T. Killian
Vice President	S. D. Bojack
Treasurer	R. O. Bent, II
Secretary	D. B. Pinkert
Assistant Secretary	J. M. Gross
Assistant Secretary	B. E. Davis

IN WITNESS WHEREOF, the undersigned have hereunto set their signatures as of the 26th day of November, 1985.

R. T. Killian

R. K. Stehn

J. M. Gross

The undersigned Assistant Secretary of the Company hereby certifies that the above signatures are the true and correct signatures of each of the Directors of the Company as of the date hereof.

B. E. Davis

EXHIBIT A

CERTIFICATE OF INCORPORATION

OF

AMOCO ENERGY TRADING CORPORATION

* * * * *

1. The name of the corporation is:

AMOCO ENERGY TRADING CORPORATION

2. The address of its registered office in the State of Delaware is Corporation Trust Center, 1209 Orange Street, in the City of Wilmington, County of New Castle. The name of its registered agent at such address is The Corporation Trust Company.

3. The nature of the business or purposes to be conducted or promoted is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of Delaware.

4. The total number of shares of stock which the corporation shall have authority to issue is One Thousand (1,000) all of such shares shall be without par value.

5. The board of directors is authorized to make, alter or repeal the by-laws of the corporation. Election of directors need not be by written ballot.

6. The name and mailing address of the incorporator is:

L. M. Custis
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware 19801

I, THE UNDERSIGNED, being the incorporator hereinbefore named, for the purpose of forming a corporation pursuant to the General Corporation Law of Delaware, do make this certificate, hereby declaring and certifying that this is my act and deed and the facts herein stated are true, and accordingly have hereunto set my hand this 26th day of November, 1985.

L. M. Custis

L. M. Custis

Received for Record

November 26th, A. D. 1985.

Leo J. Dugan, Jr., Recorder.

STATE OF DELAWARE :
: SS.:
NEW CASTLE COUNTY :

Recorded in the Recorder's Office at

Wilmington, Vol. Page &c., the

26th day of November, A. D. 1985.

Witness my hand and official seal.

Leo J. Dugan, Jr.

Recorder.

""""""""""""""""""""""""""""""""""
" Recorders Office "
" New Castle Co. Del. "
" Mercy Justice "
""""""""""""""""""""""""""""""""""

EXHIBIT B

AMENDED AND RESTATED

BY-LAWS

OF

AMOCO ENERGY TRADING CORPORATION

(A Delaware Corporation)

November 26, 1985

ARTICLE I

STOCKHOLDERS

1. CERTIFICATES REPRESENTING STOCK. Every holder of stock in the corporation shall be entitled to have a certificate signed by, or in the name of, the corporation by the President or a Vice President and by the Treasurer or an Assistant Treasurer or the Secretary or an Assistant Secretary of the corporation certifying the number of shares owned by him in the corporation. Any and all signatures on any such certificate may be facsimiles. In case any officer, transfer agent, or registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, transfer agent, or registrar before such certificate is issued, it may be issued by the corporation with the same effect as if he were such officer, transfer agent, or registrar at the date of issue.

Whenever the corporation shall be authorized to issue more than one class of stock or more than one series of any class of stock, and whenever the corporation shall issue any shares of its stock as partly paid stock, the certificates representing shares of any such class or series or of any such partly paid stock shall set forth thereon the statements prescribed by the General Corporation Law. Any restrictions on the transfer or registration of transfer of any shares of stock of any class or series shall be noted conspicuously on the certificate representing such shares.

The corporation may issue a new certificate of stock in place of any certificate theretofore issued by it, alleged to have been lost, stolen, or destroyed, and the Board of Directors may require the owner of any lost, stolen, or destroyed certificate, or his legal representative, to give the corporation a bond sufficient to indemnify the corporation against any claim that may be made against it on account of the alleged loss, theft, or destruction of any such certificate or the issuance of any such new certificate.

2. STOCK TRANSFERS. Upon compliance with provisions restricting the transfer or registration of transfer of shares of stock, if any, transfers or registration of transfers of shares

of stock of the corporation shall be made only on the stock ledger of the corporation by the registered holder thereof, or by his attorney thereunto authorized by power of attorney duly executed and filed with the Secretary of the corporation or with a transfer agent or a registrar, if any, and on surrender of the certificate or certificates for such shares of stock properly endorsed and the payment of all taxes due thereon.

3. RECORD DATE FOR STOCKHOLDERS. For the purpose of determining the stockholders entitled to notice of or to vote at any meeting of stockholders or any adjournment thereof, or to express consent to corporate action in writing without a meeting, or entitled to receive payment of any dividend or other distribution or the allotment of any rights, or entitled to exercise any rights in respect of any change, conversion, or exchange of stock or for the purpose of any other lawful action, the directors may fix, in advance, a record date, which shall not be more than sixty days nor less than ten days before the date of such meeting, nor more than sixty days prior to any other action. If no record date is fixed, the record date for determining stockholders entitled to notice of or to vote at a meeting of stockholders shall be at the close of business on the day next preceding the day on which notice is given, or, if notice is waived, at the close of business on the day next preceding the day on which the meeting is held; the record date for determining stockholders entitled to express consent to corporate action in writing without a meeting, when no prior action by the Board of Directors is necessary, shall be the day on which the first written consent is expressed; and the record date for determining stockholders for any other purpose shall be at the close of business on the day on which the Board of Directors adopts the resolution relating thereto. A determination of stockholders of record entitled to notice of or to vote at any meeting of stockholders shall apply to any adjournment of the meeting; provided, however, that the Board of Directors may fix a new record date for the adjourned meeting.

4. MEANING OF CERTAIN TERMS. As used herein in respect of the right to notice of a meeting of stockholders or a waiver thereof or to participate or vote thereat or to consent or dissent in writing in lieu of a meeting, as the case may be, the term "share" or "shares" or "share of stock" or "shares of stock" or "stockholder" or "stockholders" refers to an outstanding share or shares of stock and to a holder or holders of record of outstanding shares of stock when the corporation is authorized to issue only one class of shares of stock, and said reference is also intended to include any outstanding share or shares of stock and any holder or holders of record of outstanding shares of stock of any class upon which or upon whom the certificate of incorporation confers such rights where there are two or more classes or series of shares of stock or upon which or upon whom the General Corporation Law confers such rights notwithstanding that the certificate of incorporation may provide for more than one class or series of shares of stock, one or more of which are limited or denied such rights thereunder; provided, however, that no such right shall vest in the event of an increase or a

decrease in the authorized number of shares of stock of any class or series which is otherwise denied voting rights under the provisions of the certificate of incorporation, except as any provision of law may otherwise require.

5. STOCKHOLDER MEETINGS.

- TIME. The annual meeting shall be held on the date and at the time fixed, from time to time, by the directors, provided, that the first annual meeting shall be held on a date within thirteen months after the organization of the corporation, and each successive annual meeting shall be held on a date within thirteen months after the date of the preceding annual meeting. A special meeting shall be held on the date and at the time fixed by the directors.

- PLACE. Annual meetings and special meetings shall be held at such place, within or without the State of Delaware, as the directors may, from time to time, fix. Whenever the directors shall fail to fix such place, the meeting shall be held at the registered office of the corporation in the State of Delaware.

- CALL. Annual meetings and special meetings may be called by the directors or by the President, any Vice President or any other officer instructed by the directors to call the meeting.

- NOTICE OR WAIVER OF NOTICE. Written notice of all meetings shall be given, stating the place, date, and hour of the meeting and stating the place within the city or other municipality or community at which the list of stockholders of the corporation may be examined. The notice of an annual meeting shall state that the meeting is called for the election of directors and for the transaction of other business which may properly come before the meeting, and shall (if any other action which could be taken at a special meeting is to be taken at such annual meeting) state the purpose or purposes. The notice of a special meeting shall in all instances state the purpose or purposes for which the meeting is called. The notice of any meeting shall also include, or be accompanied by, any additional statements, information, or documents prescribed by the General Corporation Law. Except as otherwise provided by the General Corporation Law, a copy of the notice of any meeting shall be given, personally or by mail, not less than ten days nor more than sixty days before the date of the meeting, unless the lapse of the prescribed period of time shall have been waived, and directed to each stockholder at his record address or at such other address which he may have furnished by request in writing to the Secretary of the corporation. Notice by mail shall be deemed to be given when deposited, with postage thereon prepaid, in the United States Mail. If a meeting is adjourned to another time, not more than thirty days hence, and/or to another place, and if an announcement of the adjourned time and/or place is made at the meeting, it shall not be necessary to give notice of the adjourned meeting unless the directors, after adjournment, fix a new record date for the adjourned meeting. Notice need not be given to any stockholder who submits a written waiver of notice signed by him before or after the time stated therein. Attendance of a stockholder at a meeting of stockholder shall constitute a waiver of notice of such meeting, except when the stockholder attends the meeting for the express purpose of objecting, at the beginning of the meeting, to the transaction of any business because the meeting is not lawfully called or convened. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the stockholders need be specified in any written waiver of notice.

- STOCKHOLDER LIST. The officer who has charge of the stock ledger of the corporation shall prepare and make, at least ten days before every meeting of stockholders, a complete list of the stockholders, arranged in alphabetical order, and showing the address of each stockholder and the number of shares registered in the name of each stockholder. Such list shall be open to the examination of any stockholder, for any purpose germane to the meeting, during ordinary business hours, for a period of at least ten days prior to the meeting, either at a place within the city or other municipality or community where the meeting is to be held, which place shall be specified in the notice of the meeting, or if not so specified, at the place where the meeting is to be held. The list shall also be produced and kept at the time and place of the meeting during the whole time thereof, and may be inspected by any stockholder who is present. The stock ledger shall be the only evidence as to who are the stockholders entitled to examine the stock ledger, the list required by this section or the books of the corporation, or to vote at any meeting of stockholders.

- CONDUCT OF MEETING. Meetings of the stockholders shall be presided over by one of the following officers in the order of seniority and if present and acting--the President, a Vice President, or, if none of the foregoing is in office and present and acting, by a chairman to be chosen by the stockholders. The Secretary of the corporation, or in his absence, an Assistant Secretary, shall act as secretary of every meeting, but if neither the Secretary nor an Assistant Secretary is present the Chairman of the meeting shall appoint a secretary of the meeting.

- PROXY REPRESENTATION. Every stockholder may authorize another person or persons to act for him by proxy in all matters in which a stockholder is entitled to participate, whether by waiving notice of any meeting, voting or participating at a meeting, or expressing consent or dissent without a meeting. Every proxy must be signed by the stockholder or by his attorney-in-fact. No proxy shall be voted or acted upon after three years from its date unless such proxy provides for a longer period. A duly executed proxy shall be irrevocable if it states that it is irrevocable and, if, and only as long as, it is coupled with an interest sufficient in law to support an irrevocable power. A proxy may be made irrevocable regardless of whether the interest with which it is coupled is an interest in the stock itself or an interest in the corporation generally.

- QUORUM. The holders of a majority of the outstanding shares of stock shall constitute a quorum at a meeting of stockholders for the transaction of any business. The stockholders present may adjourn the meeting despite the absence of a quorum.

- VOTING. Each share of stock shall entitle the holder thereof to one vote. In the election of directors, a plurality of the votes cast shall elect. Any other action shall be authorized by a majority of the votes cast except where the General Corporation Law prescribes a different percentage of votes and/or a different exercise of voting power, and except as may be otherwise prescribed by the provisions of the certificate of incorporation and these By-Laws. In the election of directors, and for any other action, voting need not be by ballot.

6. STOCKHOLDER ACTION WITHOUT MEETINGS. Any action required by the General Corporation Law to be taken at any annual or special meeting of stockholders, or any action which may be taken at any annual or special meeting of stockholders, may be taken without a meeting, without prior notice and without a vote, if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted. Prompt notice of the taking of the corporate action without a meeting by less than unanimous written consent shall be given to those stockholders who have not consented in writing.

ARTICLE II

DIRECTORS

1. FUNCTIONS AND DEFINITION. The business and affairs of the corporation shall be managed by or under the direction of the Board of Directors of the corporation. The Board of Directors shall have the authority to fix the compensation of the members thereof. The use of the phrase "whole board" herein refers to the total number of directors which the corporation would have if there were no vacancies.

2. QUALIFICATIONS AND NUMBER. A director need not be a stockholder, a citizen of the United States, or a resident of the State of Delaware. The initial Board of Directors shall consist of three persons. Thereafter the number of directors constituting the whole board shall be at least one. Subject to the foregoing limitation and except for the first Board of Directors, such number may be fixed from time to time by action of the stockholders or of the directors, or, if the number is not fixed, the number shall be three. The number of directors may be increased or decreased by action of the stockholders or of the directors.

3. ELECTION AND TERM. The first Board of Directors, unless the members thereof shall have been named in the certificate of incorporation, shall be elected by the incorporator or incorporators and shall hold office until the first annual meeting of stockholders and until their successors are elected and qualified or until their earlier resignation or removal. Any director may resign at any time upon written notice to the corporation. Thereafter, directors who are elected at an annual meeting of stockholders, and directors who are elected in the interim to fill vacancies and newly created directorships, shall hold office until the next annual meeting of stockholders and until their successors are elected and qualified or until their earlier resignation or removal. In the interim between annual meetings of stockholders or of special meetings of stockholders called for the election of directors and/or for the removal of one or more directors and for the filling of any vacancy in that connection, newly created directorships and any vacancies in the Board of Directors, including unfilled vacancies resulting from the removal of directors for cause or without cause, may be filled by the vote of a majority of the remaining directors then in office, although less than a quorum, or by the sole remaining director.

4. MEETINGS.

- TIME. Meetings shall be held at such time as the Board shall fix, except that the first meeting of a newly elected Board shall be held as soon after its election as the directors may conveniently assemble.

- PLACE. Meetings shall be held at such place within or without the State of Delaware as shall be fixed by the Board.

- CALL. No call shall be required for regular meetings for which the time and place have been fixed. Special meetings may be called by or at the direction of the President, or of a majority of the directors in office.

- NOTICE OR ACTUAL OR CONSTRUCTIVE WAIVER. No notice shall be required for regular meetings for which the time and place have been fixed. Written, oral, or any other mode of notice of the time and place shall be given for special meetings in sufficient time for the convenient assembly of the directors thereat. Notice need not be given to any director or to any member of a committee of directors who submits a written waiver of notice signed by him before or after the time stated therein. Attendance of any such person at a meeting shall constitute a waiver of notice of such meeting, except when he attends a meeting for the express purpose of objecting, at the beginning of the meeting, to the transaction of any business because the meeting is not lawfully called or convened. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the directors need be specified in any notice or written waiver of notice.

- QUORUM AND ACTION. A majority of the whole Board shall constitute a quorum except when a vacancy or vacancies prevents such majority, whereupon a majority of the directors in office shall constitute a quorum, provided, that such majority shall constitute at least one-third of the whole Board. A majority of the directors present, whether or not a quorum is present, may adjourn a meeting to another time and place. Except as herein otherwise provided, and except as otherwise provided by the General Corporation Law, the vote of the majority of the directors present at a meeting at which a quorum is present shall be the act of the Board. The quorum and voting provisions herein stated shall not be construed as conflicting with any provisions of the General Corporation Law and these By-Laws which govern a meeting of directors held to fill vacancies and newly created directorships in the Board or action of disinterested directors.

Any member or members of the Board of Directors or of any committee designated by the Board may participate in a meeting of the Board, or any such committee, as the case may be, by means of conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear each other.

- CHAIRMAN OF THE MEETING. The President, if a director, or any other director chosen by the Board shall preside at all meetings.

5. REMOVAL OF DIRECTORS. Except as may otherwise be provided by the General Corporation Law, any director or the entire Board of Directors may be removed, with or without cause, by the holders of a majority of the shares then entitled to vote at an election of directors.

6. COMMITTEES. The Board of Directors may, by resolution passed by a majority of the whole Board, designate one or more committees, each committee to consist of one or more of the directors of the corporation. The Board may designate one or more directors as alternate members of any committee, who may replace any absent or disqualified member at any meeting of the committee. In the absence or disqualification of any member of any such committee or committees, the member or members thereof present at any meeting and not disqualified from voting, whether or not he or they constitute a quorum, may unanimously appoint another member of the Board of Directors to act at the meeting in the place of any such absent or disqualified member. Any such committee, to the extent provided in the resolution of the Board, shall have and may exercise the powers and authority of the Board of Directors in the management of the business and affairs of the corporation with the exception of any authority the delegation of which is prohibited by Section 141 of the General Corporation Law, and may authorize the seal of the corporation to be affixed to all papers which may require it.

7. WRITTEN ACTION. Any action required or permitted to be taken at any meeting of the Board of Directors or any committee thereof may be taken without a meeting if all members of the

Board or committee, as the case may be, consent thereto in writing, and the writing or writings are filed with the minutes of proceedings of the Board or committee.

ARTICLE III

OFFICERS

1. OFFICERS. The officers of the corporation shall consist of a President, a Secretary, a Treasurer, and, if deemed necessary, expedient, or desirable by the Board of Directors, an Executive Vice President, one or more other Vice Presidents, one or more Assistant Secretaries, one or more Assistant Treasurers, a Controller, one or more Assistant Controllers and such other officers with such titles as the resolution of the Board of Directors choosing them shall designate. Except as may otherwise be provided in the resolution of the Board of Directors choosing him, no officer need be a director. Any number of offices may be held by the same person, as the directors may determine.

Unless otherwise provided in the resolution choosing him, each officer shall be chosen for a term which shall continue until the meeting of the Board of Directors following the next annual meeting of stockholders and until his successor shall have been chosen and qualified.

2. THE PRESIDENT. The president shall be the chief executive officer of the corporation; he shall preside at all meetings of the stockholders and directors, shall be ex officio a member of all standing committees, shall have general and active management of the business of the corporation, and shall see that all orders and resolutions of the board are carried into effect. He shall execute bonds, mortgages, and other contracts requiring a seal, under the seal of the corporation, except where required or permitted by law to be otherwise signed and executed and except where the signing and execution thereof shall be expressly delegated by the board of directors to some other officer or agent of the corporation.

3. VICE PRESIDENTS. The vice presidents in the order of their seniority shall, in the absence or disability of the president, perform the duties and exercise the power of the president, and shall perform such other duties as the board of directors shall prescribe.

4. THE SECRETARY AND ASSISTANT SECRETARIES. The secretary shall attend all sessions of the board and all meetings of the stockholders, record all votes and the minutes of all proceedings in a book to be kept for that purpose, and shall perform like duties for the standing committees when required. He shall give, or cause to be given, notice of all meetings of the stockholders and special meetings of the board of directors and shall perform such other duties as may be prescribed by the board of directors or president, under whose supervision he shall be. He shall keep in safe custody the seal of the corporation and, when authorized by the board, affix the same to any instrument requiring it; and,

when so affixed, it shall be attested by his signature or by the signature of the treasurer or an assistant secretary. The assistant secretaries in order of their seniority shall, in the absence or disability of the secretary, perform the duties and exercise the powers of the secretary and shall perform such other duties as the board of directors shall prescribe.

5. THE TREASURER AND ASSISTANT TREASURERS. The treasurer shall have the custody of the corporate funds and securities, shall keep full and accurate accounts of receipts and disbursements in books belonging to the corporation, and shall deposit all moneys and other valuable effects in the name and to the credit of the corporation in such depositories as may be designated by the board of directors. He shall disburse the funds of the corporation as may be ordered by the board, taking proper vouchers for such disbursements and shall render to the president and directors, at the regular meetings of the board or whenever they may require it, an account of all his transactions as treasurer.

If required by the board of directors, he shall give the corporation a bond (which shall be renewed every six years) in such sum and with such surety or sureties as shall be satisfactory to the board for the faithful performance of the duties of his office and for the restoration to the corporation, in case of his death, resignation, retirement, or removal from office, of all books, papers, vouchers, money, and other property of whatever kind in his possession or under his control belonging to the corporation.

The assistant treasurers in the order of their seniority shall, in the absence or disability of the treasurer, perform the duties and exercise the powers of the treasurer and shall perform such other duties as the board of directors shall prescribe.

6. THE CONTROLLER AND ASSISTANT CONTROLLERS. The controller shall have general charge and responsibility for the accounting and auditing affairs of the corporation, the keeping of the corporate, general and cost accounting books and records of the company, and other documents and papers necessary to properly reflect the business and corporate transactions upon the books of the corporation and shall report to the president and the directors, whenever they may so require, an account of his transactions as controller. He shall also certify as to the financial condition of the corporation.

The assistant controller, in the absence or disability of the controller, shall exercise the powers of the controller and shall perform such other duties as the board of directors shall prescribe.

ARTICLE IV

CERTIFICATES OF STOCK

The certificates of stock of the corporation shall be numbered and shall be entered in the books of the corporation as they are issued. They shall exhibit the holder's name and number of shares and shall be signed by the president or a vice president and the treasurer or an assistant treasurer or the secretary or an assistant secretary. If any stock certificate is signed (1) by a transfer agent or an assistant transfer agent or (2) by a transfer clerk acting on behalf of the corporation and a registrar, the signature of any such officer may be facsimile.

ARTICLE V

CORPORATE SEAL

The corporate seal shall be in such form as the Board of Directors shall prescribe.

ARTICLE VI

FISCAL YEAR

The fiscal year of the corporation shall be a calendar year or such other twelve-month period chosen by the Board of Directors.

ARTICLE VII

CONTROL OVER BY-LAWS

Subject to the provisions of the certificate of incorporation and the provisions of the General Corporation Law, the power to amend, alter or repeal these By-Laws and to adopt new By-Laws may be exercised by the Board of Directors or by the stockholders.

I HEREBY CERTIFY that the foregoing is a full, true and correct copy of the By-Laws of AMOCO ENERGY TRADING CORPORATION, a Delaware corporation, as in effect on the date hereof.

WITNESS my hand and the seal of the corporation.

Dated:

____
Secretary of
AMOCO ENERGY TRADING CORPORATION

(SEAL)

EXHIBIT C

NUMBER 1

SHARES 100

INCORPORATED UNDER THE LAWS OF THE STATE OF DELAWARE

AMOCO ENERGY TRADING CORPORATION

AUTHORIZED CAPITAL STOCK 1,000 SHARES WITHOUT PAR VALUE

This Certifies That AMOCO PRODUCTION COMPANY is the owner of ONE HUNDRED full paid and non-assessable

SHARES OF THE CAPITAL STOCK OF AMOCO ENERGY TRADING CORPORATION,

transferable on the books of the Corporation in person or by duly authorized Attorney upon surrender of this Certificate properly endorsed.

In Witness Whereof, the said Corporation has caused this Certificate to be signed by its duly authorized officers and sealed with the Seal of the Corporation,

this TWENTY SIXTH day of NOVEMBER A.D. 19 85

D. B. Pinkert
SECRETARY

H. M. Hawkins
PRESIDENT

STATEMENT

OF

SOLE INCORPORATOR

OF

AMOCO ENERGY TRADING CORPORATION

* * * * *

The certificate of incorporation of this corporation having been filed in the office of the Secretary of State, the undersigned, being the sole incorporator named in said certificate, does hereby state that the following actions were taken on this day for the purpose of organizing this corporation:

1. The following persons were elected as directors to hold office until the first annual meeting of stockholders or until their respective successors are elected and qualified:

R. T. Killian

R. K. Stehn

J. M. Gross

2. The board of directors was authorized to make and adopt the by-laws of the corporation and, in its discretion, to issue the shares of the capital stock of this

corporation to the full amount or number of shares authorized by the certificate of incorporation, in such amounts and for such considerations as from time to time shall be determined by the board of directors and as may be permitted by law.

Dated, November 26th, 1985.

L M Custis

L. M. Custis

* * * * *

AMOCO ENERGY TRADING CORPORATION

* * * * *

* * * * *

C O R P O R A T E   R E C O R D S

* * * * *

* * * * *

CERTIFICATE OF INCORPORATION

OF

AMOCO ENERGY TRADING CORPORATION

* * * * *

1. The name of the corporation is:

AMOCO ENERGY TRADING CORPORATION

2. The address of its registered office in the State of Delaware is Corporation Trust Center, 1209 Orange Street, in the City of Wilmington, County of New Castle. The name of its registered agent at such address is The Corporation Trust Company.

3. The nature of the business or purposes to be conducted or promoted is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of Delaware.

4. The total number of shares of stock which the corporation shall have authority to issue is One Thousand (1,000) all of such shares shall be without par value.

5. The board of directors is authorized to make, alter or repeal the by-laws of the corporation. Election of directors need not be by written ballot.

6. The name and mailing address of the incorporator is:

L. M. Custis
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware 19801

I, THE UNDERSIGNED, being the incorporator hereinbefore named, for the purpose of forming a corporation pursuant to the General Corporation Law of Delaware, do make this certificate, hereby declaring and certifying that this is my act and deed and the facts herein stated are true, and accordingly have hereunto set my hand this 26th day of November, 1985.

L. M. Custis

L. M. Custis

Received for Record

November 26th, A. D. 1985.

Leo J. Dugan, Jr., Recorder.

STATE OF DELAWARE :
: SS.:
NEW CASTLE COUNTY :

Recorded in the Recorder's Office at Wilmington, Vol. Page &c., the 26th day of November, A. D. 1985.

Witness my hand and official seal.

Leo J. Dugan, Jr.

Recorder.

""""""""""""""""""""""""""
" Recorders Office "
" New Castle Co. Del. "
" Mercy Justice "
""""""""""""""""""""""""""

S T A T E M E N T

OF

SOLE INCORPORATOR

OF

AMOCO ENERGY TRADING CORPORATION

* * * * *

The certificate of incorporation of this corporation having been filed in the office of the Secretary of State, the undersigned, being the sole incorporator named in said certificate, does hereby state that the following actions were taken on this day for the purpose of organizing this corporation:

1. The following persons were elected as directors to hold office until the first annual meeting of stockholders or until their respective successors are elected and qualified:

R. T. Killian

R. K. Stehn

J. M. Gross

2. The board of directors was authorized to make and adopt the by-laws of the corporation and, in its discretion, to issue the shares of the capital stock of this

corporation to the full amount or number of shares authorized by the certificate of incorporation, in such amounts and for such considerations as from time to time shall be determined by the board of directors and as may be permitted by law.

Dated, November 26th, 1985.

L.M. Custis

L. M. Custis

EXHIBIT C

OFFICERS AND BUSINESS ADDRESSES
BP ENERGY COMPANY

OFFICER NAME	OFFICE	BUSINESS ADDRESS
D.C. Byers	President	501 Westlake Park Blvd., Houston, TX 77079
M. O'Sullivan	VP	501 Westlake Park Blvd., Houston, TX 77079
D.B. Pinkert	VP	4101 Winfield Road, Warrenville, IL 60555
W.T. Benham	VP	501 Westlake Park Blvd., Houston, TX 77079
Brian E. Frank	VP	240 - 4 Avenue S. W., Calgary, AB Canada T2P 2H8
P. Nigel Hill	VP	501 Westlake Park Blvd., Houston, TX 77079
A.H. Netemeyer	VP	501 Westlake Park Blvd., Houston, TX 77079
J.A. Taylor	VP	501 Westlake Park Blvd., Houston, TX 77079
O.A. Alvarez	VP	501 Westlake Park Blvd., Houston, TX 77079
Nigel Preece	VP	501 Westlake Park Blvd., Houston, TX 77079
D.J. Reistroffer	VP	4101 Winfield Road, Warrenville, IL 60555
P.D. Wessells	VP & GTO	4101 Winfield Road, Warrenville, IL 60555
S.J. Riney	VP & CFO	4101 Winfield Road, Warrenville, IL 60555
R.J. Novaria	Treas	4101 Winfield Road, Warrenville, IL 60555
M.A. Lukas	Asst Treas	4101 Winfield Road, Warrenville, IL 60555
L.P. Peterson	Asst Treas	4101 Winfield Road, Warrenville, IL 60555
M.E. Labadie	Asst Treas	509 S. Boston Avenue, Tulsa, OK 74103-4346
S.D. Funk	Asst Treas	509 S. Boston Avenue, Tulsa, OK 74103-4346
C.A. Jadomska	Asst Treas	4101 Winfield Road, Warrenville, IL 60555
M. Susan Horvat	Asst Treas	4101 Winfield Road, Warrenville, IL 60555
M.C. Mroz	Asst Treas	4101 Winfield Road, Warrenville, IL 60555
D.A. Plumb	Secretary	4101 Winfield Road, Warrenville, IL 60555
W.M. Burden	Asst Secr	501 Westlake Park Blvd., Houston, TX 77079
D.A. Dowling	Asst Secr	4101 Winfield Road, Warrenville, IL 60555
F.T. Kolb	Asst Secr	501 Westlake Park Blvd., Houston, TX 77079
J.M. Stuhldreher	Asst Secr	501 Westlake Park Blvd., Houston, TX 77079
M.S. Haskins	Asst Secr	501 Westlake Park Blvd., Houston, TX 77079
W.T. Mangan	Asst Secr	4101 Winfield Road, Warrenville, IL 60555
G.E. Stein	Asst Secr	4101 Winfield Road, Warrenville, IL 60555

EXHIBIT D

Affiliates of Applicant Registered to Conduct Business in Pennsylvania

Affiliate	Principal Operating Office	Jurisdictional Public Utility?
Atlantic Richfield Company	28100 Torch Pkwy, Warrenville, IL 60555	No
American Oil Company	4101 Winfield Road, Warrenville, IL 60555	No
Amoco Marketing Environmental Services Company	4101 Winfield Road, Warrenville, IL 60555	No
Atlantic Richfield Company d/b/a Group Environmental Management Company	28100 Torch Pkwy, Warrenville, IL 60555	No
ARCO Products Company	4101 Winfield Road, Warrenville, IL 60555	No
ARCO Environmental Remediation, L.L.C.	4101 Winfield Road, Warrenville, IL 60555	No
BP Marine Limited	Chertsey Road, Sunbury on Thames, Middlesex, TW16 7BP, England	No
BP America Production Company	501 Westlake Park Blvd, Houston, TX 77079	No
BP Corporation North America Inc.	4101 Winfield Road, Warrenville, IL 60555	No
BP Amoco Chemical Company	4101 Winfield Road, Warrenville, IL 60555	No
BP Products North America Inc.	4101 Winfield Road, Warrenville, IL 60555	No
BP Oil Supply Company	4101 Winfield Road, Warrenville, IL 60555	No
BP Global Special Products (America) Inc.	150 W. Warrenville Rd, Naperville, IL 60563-8473	No
BP Lubricants USA Inc.	1500 Valley Rd, Wayne, NJ 07470	No
BP Solar International LLC	630 Solarex Ct., Frederick, MD 21703	No
BP Oil Pipeline Company	4101 Winfield Road, Warrenville, IL 60555	No
BP Canada Energy Marketing Corp.	4101 Winfield Road, Warrenville, IL 60555	No
BP America Inc.	4101 Winfield Road, Warrenville, IL 60555	No
Castrol Industrial North America Inc.	4101 Winfield Road, Warrenville, IL 60555	No
Energy Global Investments (USA) Inc.	4101 Winfield Road, Warrenville, IL 60555	No
Innovene USA LLC	200 East Randolph St, Chicago, IL 60601	No
Vastar Gas Marketing, Inc.	4101 Winfield Road, Warrenville, IL 60555	No

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Ownership Chart for BP Energy Company

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world

Click entity name to view datasheet.

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6		Owning Entity (See Help for information on multiple ownership)	Country of Incorporation	% BP Owned
BP p.l.c.							View Ownership Chart for BP p.l.c.	England	100%
	BP America Inc.						BP p.l.c., 100%	USA	100%
		BP Corporation North America Inc.					BP America Inc., 100%	USA	100%
			BP Company North America Inc.				BP Corporation North America Inc., 100%	USA	100%
				BP America Production Company			BP Company North America Inc., 100%	USA	100%
					BP Energy Company		BP America Production Company, 100%	USA	100%
						BP Gas and Power Company	BP Energy Company, 100%	USA	100%
						IGI Resources, Inc.	BP Energy Company, 100%	USA	100%

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Ownership Chart for BP Products North America Inc.

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world

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Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6	Tier 7	Tier 8	Tier 9		Owning Entity (See Help for information on multiple ownership)	Country Incorpor
BP p.l.c.										View Ownership Chart for BP p.l.c.	England
	BP America Inc.									BP p.l.c., 100%	USA
		BP Corporation North America Inc.								BP America Inc., 100%	USA
			BP Company North America Inc.							BP Corporation North America Inc., 100%	USA
				BP Products North America Inc.						BP Company North America Inc., 65%; The Standard Oil Company, 35%	USA
					American Oil Company					BP Products North America Inc., 100%	USA
					Amoco Environmental Services Company					BP Products North America Inc., 100%	USA
					Amoco Marketing Environmental Services Company					BP Products North America Inc., 100%	USA
					Amoco Oil Holding Company					BP Products North America Inc., 100%	USA
						Amoco Corporate Development Company (Latin America)				Amoco Oil Holding Company, 100%	USA
							Amoco Servicios Mexicanos, S.A. De C.V.			BP Mexico Holding Company, S.A. de C.V., 99.998%; Amoco Corporate Development Company (Latin America), 0.002%	Mexico

bp

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Ownership Chart for BP Canada Energy Marketing Corp.

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Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6	Tier 7		Owning Entity (See Help for information on multiple ownership)	Country of Incorporation	% BP Owned
BP p.l.c.								View Ownership Chart for BP p.l.c.	England	100%
	BP America Inc.							BP p.l.c., 100%	USA	100%
		BP Corporation North America Inc.						BP America Inc., 100%	USA	100%
			BP Canada Investments Inc.					BP Corporation North America Inc., 100%	USA	100%
				Amoco Canada International Holdings B.V.				BP Canada Investments Inc., 100%	Netherlands	100%
					BP Canada Energy Company			Amoco Canada International Holdings B.V., 100%	Canada	100%
						BP Canada Energy Marketing Corp.		BP Canada Energy Company, 100%	USA	100%

bp

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Ownership Chart for IGI Resources, Inc.

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Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 6	Tier 7		Owning Entity (See Help for information on multiple ownership)	Country of Incorporation	% BP Owned
BP p.l.c.								View Ownership Chart for BP p.l.c.	England	100%
	BP America Inc.							BP p.l.c., 100%	USA	100%
		BP Corporation North America Inc.						BP America Inc., 100%	USA	100%
			BP Company North America Inc.					BP Corporation North America Inc., 100%	USA	100%
				BP America Production Company				BP Company North America Inc., 100%	USA	100%
					BP Energy Company			BP America Production Company, 100%	USA	100%
						IGI Resources, Inc.		BP Energy Company, 100%	USA	100%

EXHIBIT G

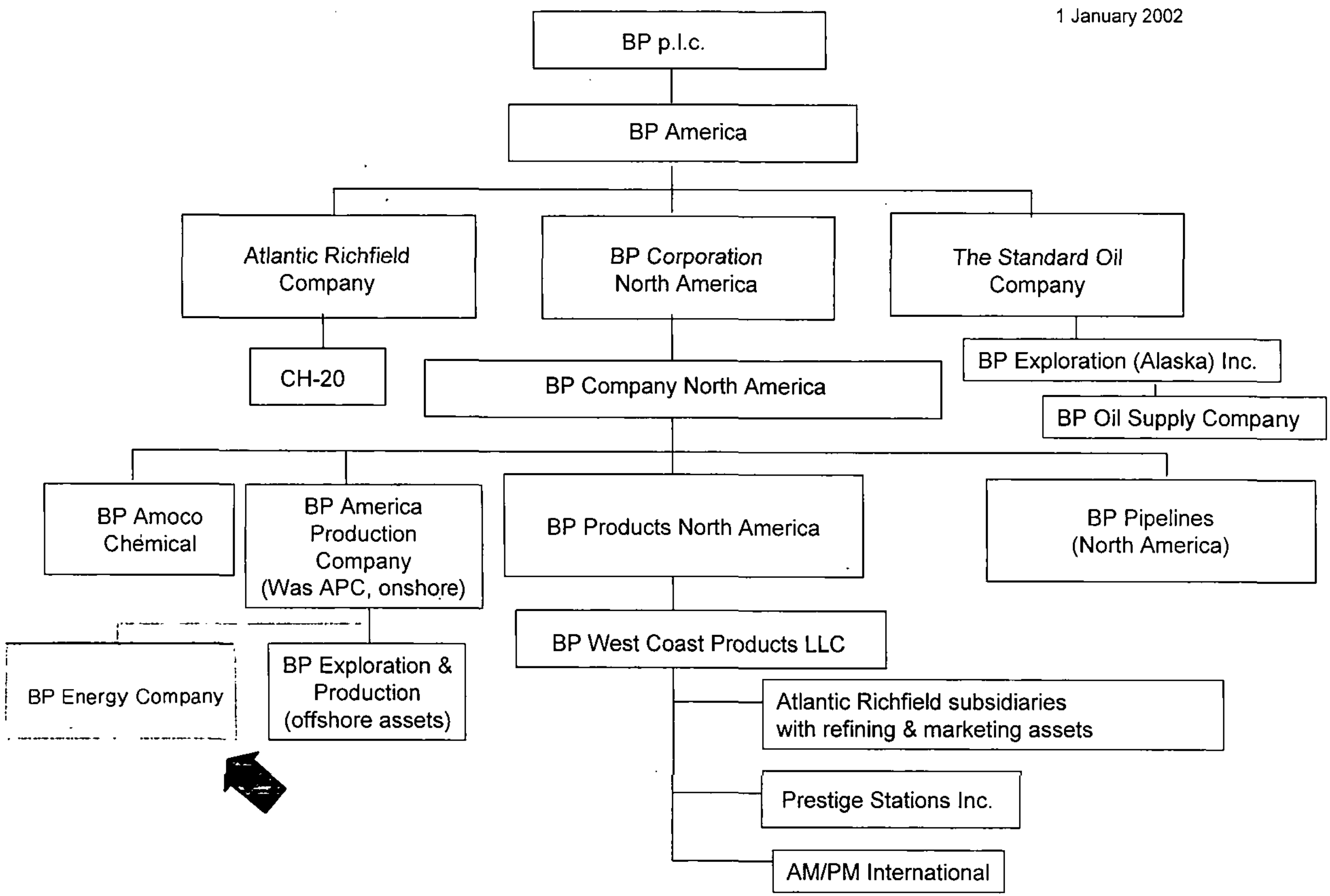
List and Status of Applicable Proceedings

(as to Applicant, BP Canada Energy Marketing Corp., and IGI Resources, Inc.)

Style of Case	Court/Docket	Subject	Status
People of the State of California v. BP Energy Company, et al	US Court of Appeals, 9th Circuit; Docket No. C-02-3311-VRW	Contract/Regulatory matter re: wholesale sales of power	Ongoing
Nancy Saint-Paul v. City of Galveston, Texas, Board of Trustees of Galveston Wharves (*BP Energy Company is intervener and defendant through cross-claim*)	112nd District Court, Galveston County, Texas; Docket No. 05CV0503	City's and Wharves Board's compliance with state law. The outcome of the proceeding could affect certain of BP's contracts, as such BP has intervened to monitor and protect its interests.	Ongoing
Nevada Power Co. v. BP Energy Company	FERC Docket No. EL02-26-000 et al	Contract/Regulatory matter re: power sales contracts	Ongoing
Duke Energy Marketing Ltd Partnership v. IGI Resources Inc.	Court of Queen's Bench, Calgary; Cause No.	Contract matter	Ongoing
Sharon Lynn Lodewick, et al. v. Dynegy, Inc., BP Energy Company, et al	Circuit Court of Oregon, County of Multnomah; Docket No. 0212-12771	Power and natural gas sales	Dismissed
Nick A. Symonds v. Dynegy, Inc., et al, including BP Energy Company	US District Court, Western District of Washington at Seattle; Docket No. CV022522	Power and natural gas sales	Dismissed
In the Matter of: Activities Affecting Price of Natural Gas in Fall of 2003	Commodity Futures Trading Commission	Industry-wide investigation CFTC announced that it did not uncover any evidence that any entity or individual engaged in activity with an intent to cause any artificial price in natural gas in late 2003.	Dismissed
BP Energy Company, Order to Show Cause	FERC Docket No. EL03-60	Regulatory matter re: power sales	Resolved through settlement
Norske Skog v. IGI Resources, Inc.	Supreme Court of British Columbia; Docket No. S020245	Contract matter	Resolved through settlement
CFTC v. BP Energy Company	Commodity Futures Trading Commission; Docket No. 05-02	Contract/Regulatory matter re: power sales contracts	Resolved through settlement
Level Propane Gases, Inc. (Debtor/Plaintiff) et al v. BP Amoco Chemical Company and BP Canada Energy Marketing Corp.	US Bankruptcy Court, Northern District of Ohio Eastern Division, Case No. 02-16172; Adversary Proceeding No. 04-1281	Litigation re: Debtor's Chapter 11 bankruptcy proceeding	Resolved through settlement
Sinclair Oil v. BP Pipelines and BP Production/BP Canada Energy Marketing Corp.	FERC Docket No. OR02-6-000	Regulatory matter	Resolved through settlement
City of Victoria v. Amoco Energy Trading Corp n/k/a BP Energy Company et al	County Court at Law No. 2, Victoria County, Texas; Docket No. 211460	City taxation matter	Inactive

EXHIBIT H

Evidence of Applicant's Financial Fitness


1 January 2002
BP p.l.c.
BP America
Atlantic Richfield Company
BP Corporation North America
The Standard Oil Company
CH-20
BP Company North America
BP Exploration (Alaska) Inc.
BP Oil Supply Company
BP Amoco Chemical
BP America Production Company (Was APC, onshore)
BP Products North America
BP Pipelines (North America)
BP Energy Company
BP Exploration & Production (offshore assets)
BP West Coast Products LLC
Atlantic Richfield subsidiaries with refining & marketing assets
Prestige Stations Inc.
AM/PM International

MEMORANDUM OF INSURANCE	DATE 11-Oct-2004

This Memorandum is issued as a matter of information only to authorized viewers for their internal use only and confers no rights upon any viewer of this Memorandum. This Memorandum does not amend, extend or alter the coverage described below. This Memorandum may only be copied, printed and distributed within an authorized viewer and may only be used and viewed by an authorized viewer for its internal use. Any other use, duplication or distribution of this Memorandum without the consent of Marsh is prohibited. "Authorized viewer" shall mean an entity or person which is authorized by the insured named herein to access this Memorandum via http://www.marsh.com/moi?client=1955. The information contained herein is as of the date referred to above. Marsh shall be under no obligation to update such information.

PRODUCER	COMPANIES AFFORDING COVERAGE
Marsh USA Inc. ("Marsh")	Co.A SELF INSURED (SEE ADDITIONAL INFORMATION BELOW)
INSURED BP AMERICA INC., BP CORPORATION NORTH AMERICA INC., AND AFFILIATES	Co.B ACE AMERICAN INSURANCE COMPANY
	Co.C
	Co.D

COVERAGES

THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED, NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS MEMORANDUM MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

CO LTR	TYPE OF INSURANCE	POLICY NUMBER	POLICY EFFECTIVE DATE	POLICY EXPIRATION DATE	LIMITS LIMITS IN USD UNLESS OTHERWISE INDICATED	
A	**GENERAL LIABILITY** COMMERCIAL GENERAL LIABILITY OCCURRENCE	SELF INSURED	01-Jul-2004	01-Jul-2005	GENERAL AGGREGATE	N/A
					PRODUCTS - COMP/OP AGG	N/A
					PERSONAL AND ADV INJURY	N/A
					EACH OCCURRENCE	N/A
					FIRE DAMAGE (ANY ONE FIRE)	N/A
					MED EXP (ANY ONE PERSON)	N/A
B	**AUTOMOBILE LIABILITY**	ISA H 08016999	01-Jul-2004	01-Jul-2005	COMBINED SINGLE LIMIT	USD 5,000,000
					BODILY INJURY (PER PERSON)	USD 5,000,000
					BODILY INJURY (PER ACCIDENT)	USD 5,000,000
					PROPERTY DAMAGE	UDS 5,000,000
	EXCESS LIABILITY				EACH OCCURRENCE	
					AGGREGATE	
	GARAGE LIABILITY				AUTO ONLY (PER ACCIDENT)	
					OTHER THAN AUTO ONLY:	
					EACH ACCIDENT	
					AGGREGATE	
B B B B	**WORKERS COMPENSATION / EMPLOYERS LIABILITY** THE PROPRIETOR / PARTNERS / EXECUTIVE OFFICERS ARE: EXCLUDED	WLRC 43978913-(AOS) WLRC 43979097 -(MN,MO,NE,NC,NJ,OK) SCFC 43979103-(MA,,WI) WLRC 43979085-(TX)	01-Jul-2004 01-Jul-2004 01-Jul-2004 01-Jul-2004	01-Jul-2005 01-Jul-2005 01-Jul-2005 01-Jul-2005	WORKERS COMP LIMITS	Statutory
					EL EACH ACCIDENT	USD 1,000,000
					EL DISEASE - POLICY LIMIT	USD 1,000,000
					EL DISEASE - EACH EMPLOYEE	USD 1,000,000

A	**PROPERTY**	SELF INSURED	01-Jul-2004	01-Jul-2005		N/A
	POLLUTION LIABILITY	SELF INSURED	01-Jul-2004	01-Jul-2005		N/A

The Memorandum of Insurance serves solely to list insurance policies, limits and dates of coverage. Any modifications hereto are not authorized.

MEMORANDUM OF INSURANCE	**DATE** 11-Oct-2004

This Memorandum is issued as a matter of information only to authorized viewers for their internal use only and confers no rights upon any viewer of this Memorandum. This Memorandum does not amend, extend or alter the coverage described below. This Memorandum may only be copied, printed and distributed within an authorized viewer and may only be used and viewed by an authorized viewer for its internal use. Any other use, duplication or distribution of this Memorandum without the consent of Marsh is prohibited. "Authorized viewer" shall mean an entity or person which is authorized by the insured named herein to access this Memorandum via http://www.marsh.com/moi?client=1955. The information contained herein is as of the date referred to above. Marsh shall be under no obligation to update such information.

PRODUCER	**INSURED**
Marsh USA Inc. ("Marsh")	BP AMERICA INC., BP CORPORATION NORTH AMERICA INC., AND AFFILIATES

ADDITIONAL INFORMATION

Any party with which the named insured is contractually required to include as additional insured is automatically granted such. However, coverage under the policy only applies to the extent of the coverage required by such contractual requirement and for the limits of liability specified in such contractual requirement, but in no event for insurance not afforded by the policy nor for limits of liability in excess of the applicable limits of liability of the policy.

Verification of Self-Insurance – General Liability, Pollution Liability and Property Coverages

BP America Inc., BP Corporation North America Inc., and its affiliates (major subsidiaries listed below), assume the risk of loss for property, pollution liability and general liability exposures, including those for which the organization may be contractually liable. Losses for which the organization is liable are covered by the significant financial resources of the BP group.

The scope *of coverage provided by our self-insured program should be considered equal to any insurance which* may be required by agreement with contractual partners.

Subsidiaries Include:

ARCO Terminal Services Corporation
BP Amoco Chemical Company
BP America Production Company
BP Energy Company
BP Exploration & Production Company
BP Products North America Inc.
BP West Coast Products LLC
BP Pipelines North America Inc.
Castrol Heavy Duty Lubricants, Inc.
Castrol North America Inc.

The Memorandum of Insurance serves solely to list insurance policies, limits and dates of coverage. Any modifications hereto are not authorized.

BP ENERGY COMPANY
TRADE AND BANK REFERENCES

TRADE REFERENCES:

American Electric Power
155 W. Narionawide Blvd, Ste 500
Columbus, Oh 43215
Attn: Mr. Frank Hilton
614-583-6725

ChevronTexaco Natural Gas
1111 Bagby St., 43rd Floor
Houston, Tx 77002
Attn: Mr. Paul Maxian
713-752-7020

ConocoPhillips Company
600 North Dairy Ashford Rd.
Houston, Tx 77079
Attn: Mr. Eric Davis
281-293-1181

Tractabel North America, Inc.
1177 West Loop South
Houston, Tx 77027
Attn: Mr. Miguel Correa
713-636-0000

BANK REFERENCE:

Chase Manhattan Bank
Two Chase Manhattan Plaza, 22nd Floor
New York, NY 10081-1000
ABA Number 021-000021
Bank Officer: Mr. Reuben Ezra
Assistant Vice President
Phone: 212-552-7412
Fax: 212-383-0699

Account Number: 910-2-548097

Dun & Bradstreet Number 62-527-5755
Federal Taxpayer ID No. 36-3421804

STANDARD
&POOR'S

GLOBAL RATINGS HANDBOOK

July 2005

ISSUER [L.T. Rating/Outlook or CWatch/S.T. Rating] ISSUE	RTG/OUTLK/ CWATCH	RATING DATE	FORMER RATING	CUSIP/ISIN NO.
US$250 mil fltg rate sr nts due 03/15/2010	BB	Ma11,04		102183AL4
US$400 mil revolving credit fac bank ln due 04/20/2007	BB	My12,04		
Bowne & Co. Inc. [B+/Stable/—]				
US$75 mil 5% conv sub deb due 10/01/2033	B-	Se19,03		103043AA3
Box Hill Life Finance PLC				
£380 million floating-rate secured notes Class A1, Class A2 (bnd ins: Ambac Assurance UK Ltd.)	AAA	De17,04		XS0205870917
Boyd Gaming Corp. [BB/Stable/B-2]				
US$200 mil 9.25% sr nts due 08/01/2009	BB-	Ap13,04	BB-/WatchN	103304AF8
US$1.1 bil 5-year revolving credit fac bank ln due 2009	BB	Ap13,04		
US$500 mil 7-year term loan B bank ln due 2011	BB	Ap13,04		
US$250 mil 8.75% sr sub nts due 04/15/2012	B+	Fe10,04	B+/WatchN	USU1021PAC87
US$300 mil 7.75% sr sub nts due 12/15/2012	B+	Fe10,04	B+/WatchN	US103304BA85
US$350 mil 6.75% sr sub nts due 04/15/2014	B+	Ma26,04		USU1021PAE44
Boyds Collection Ltd. (The) [CCC/Negative/—]				
US$165 mil 9% sr sub nts due 05/15/2008	CC	My18,05	CCC/WatchN	USU10220AA82
BP America Production Co. [AA+/Stable/A-1+]				
US$100 mil putable/callable nts due 04/20/2010	AA+	My07,03	AA+/WatchN	922380AC4
US$300 mil 6.5% sr unsecd nts due 04/01/2009	AA+	My07,03	AA+/WatchN	922380AD2
US$250 mil Med-term Nts Prog ser A: sr unsecd	AA+	My07,03	AA+/WatchN	
BP Australia Capital Markets Ltd. GTD: BP PLC				
US$8 bil Sr Unsecd/S-T Debt *med-term note prog* 01/30/1998: sr unsecd	AA+	My07,03	AA+/WatchN	
3(A)3 CP prog auth amt US$6 bil	A-1+	Ju21,86		
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: S-T debt	A-1+	Ma12,98		
BP Canada Energy Co. [AA+/Stable/A-1+]				
BP Canada Finance Co. GTD: BP PLC				
US$250 mil 3.625% nts due 01/15/2009	AA+	My07,03	AA+/WatchN	05565UAB5
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: sr unsecd	AA+	My07,03	AA+/WatchN	
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: S-T debt	A-1+	Ma12,98		
BP Capital Markets America Inc.				
CHF150 mil 7% due 02/04/2009 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	CH0008662915
US$200 mil 9.5% sf debs due 06/15/2017 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	
US$194.2 mil med-term note program ser A: sr unsecd (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	
US$300 mil med-term note program: sr unsecd (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: sr unsecd (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	
US$175 mil 4.2% nts due 06/15/2018 (Gtd: BP PLC)	AA+	Jn04,03		103730AA8
3(A)3 CP prog auth amt US$6 bil (Gtd: BP PLC)	A-1+	Ju21,86		
EURO CP prog auth amt US$6 bil (Gtd: BP PLC)	A-1+	Ju21,86		
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: S-T debt (Gtd: BP PLC)	A-1+	Ma12,98		
BP Capital Markets PLC				
CHF600 mil 2.5% nts due 05/10/2006 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	CH0005882458
EUR300 mil 4.75% nts due 10/02/2006 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	XS0145526934
US$450 mil 4.625% nts due 12/12/2005 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	XS0139935216
US$300 mil 4.125% nts due 03/23/2009 (Gtd: BP PLC)	AA+	Ma16,05		XS0214988742
£450 mil 4.25% nts due 09/12/2006 (Gtd: BP PLC)	AA+	Se09,03		XS0176116076
£250 mil 5.125% bnds due 12/07/2008 (Gtd: BP PLC)	AA+	No04,03		XS0180026477
US$750 mil 2.75% nts due 12/29/2006 (Gtd: BP PLC)	AA+	No10,03		055650AK4
£350 mil 5% nts due 12/27/2007 (Gtd: BP PLC)	AA+	Ap30,04		XS0192028446
AUD150 mil 5.625% nts due 05/18/2010 (Gtd: BP PLC)	AA+	My09,05		XS0219268686
£250 mil 5% nts due 03/16/2007 (Gtd: BP PLC)	AA+	Ma02,05		XS0214117953
US$500 mil 3.375% bnds due 12/15/2008 (Gtd: BP PLC)	AA+	No15,04		XS0205367997
US$500 mil 3.25% nts due 12/31/2007 (Gtd: BP PLC)	AA+	Se16,04		XS0201339297
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: sr unsecd (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	
£200 mil 4.875% nts due 12/18/2006 (Gtd: BP PLC)	AA+	De08,03		XS0182245778
AUD100 mil 5.5% nts due 12/17/2008 (Gtd: BP PLC)	AA+	No29,04		XS0206914094
US$500 mil 2.625% nts due 03/15/2007 (Gtd: BP PLC)	AA+	Se26,03		055650AH1
US$250 mil 2.35% nts due 06/15/2006 (Gtd: BP PLC)	AA+	My07,03	AA+/WatchN	055650AE8
3(A)3 CP prog auth amt US$6 bil (Gtd: BP PLC)	A-1+	Ju21,86		
EURO CP prog auth amt US$6 bil (Gtd: BP PLC)	A-1+	Ju21,86		
US$8 bil Sr Unsecd/S-T Debt med-term note prog 01/30/1998: S-T debt (Gtd: BP PLC)	A-1+	Ma12,98		
BP Company North America Inc. [AA+/Stable/NR]				
US$500 mil 6% gtd nts due 06/09/2008 (Gtd: BP Corporation North America Inc.)	AA+	My07,03	AA+/WatchN	XS0087845581
US$300 mil 6.5% gtd nts due 08/01/2007 (Gtd: BP Corporation North America Inc.)	AA+	My07,03	AA+/WatchN	031905AA0
BP Corporation North America Inc. [AA+/Stable/A-1+]				
BP Finance PLC GTD: BP PLC				
US$420 mil 3% exchgble bnds due 02/09/2006	AA+	My07,03	AA+/WatchN	USG12800AA25
BP PLC [AA+/Stable/A-1+]				
BP Products North America Inc. [AA+/Stable/—]				
BP Trinidad and Tobago LLC				
4(2) CP prog auth amt US$250 mil (Gtd: BP PLC)	A-1+	Fe08,02		
BPB PLC [BBB+/Stable/A-2]				
EUR500 mil bank ln	BBB+	Fe11,00		
EUR400 mil 6.5% bnds due 03/17/2010	*BBB+*	*Fe22,00*		*XS0109134113*
BPC Holding Corp. [B+/Stable/—]				
BPE Capital International Ltd. GTD: Banco Popular Espanol, S.A.				
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: sr unsecd	AA	No04,97		
EUR100 mil callable step up nts due 04/27/2010	AA-	Ap18,00		XS0110678678
US$50 mil fltg rate sub nts ser 2 due 05/30/2010	AA-	No17,00		XS0111940366
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: sub	AA-	No04,97		
US$50 mil fltg rate sub nts ser 3 due 06/15/2010	AA-	No17,00		XS0112589725
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: S-T debt	A-1+	No04,97		
BPE Finance International Ltd. GTD: Banco Popular Espanol, S.A.				
EUR152.449 mil fltg rate due 04/23/2009	AA	Ap30,98		
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: sr unsecd	AA	No04,97		
EUR12 mil Index-linked nts ser 75 due 10/31/2005	AA	No21,02		XS0155996779
EUR10 mil callable fxd/fltg rt bnds ser 78 due 11/12/2017	AA	No21,02		XS0157822007
EUR10 mil var rate EUR10 mil Index-linked nts ser 74 due 10/31/2005	AA	No21,02		
EUR300 mil fltg rate nts ser 82 due 12/16/2005	AA	Ja17,03		XS0158980119
EUR12.6 mil Fxd/fltg rate bnds ser 77 due 11/06/2017	AA	No21,02		XS0157628610
EUR8.6 mil callable fxd/fltg rate bnds ser 76 due 11/06/2017	AA	No21,02		XS0157628370
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: sub	AA-	No04,97		
US$6 bil Sr Unsecd/Sub/S-T Debt med-term note prog 11/03/1997: S-T debt	A-1+	No04,97		
BPE Financiaciones S.A. GTD: Banco Popular Espanol, S.A.				
EUR8 bil Sr Unsecd/Sub/S-T Debt Domestic fixed income note prog : sr unsecd	AA	Au02,04		
EUR1 bil fltg rate nts ser 2 due 07/30/2009	AA	Ju27,04		ES0357080011
EUR1 bil fltg rate nts ser 6 due 05/26/2010	AA	Jn02,05		ES0357080052
EUR1.5 bil fltg rate nts ser 1 due 07/30/2007	AA	Ju27,04		ES0357080003
EUR1 bil fltg rate med-term nts ser 3 due 04/08/2006	AA	Oc06,04		ES0357080029
EUR500 mil fltg rate med-term nts ser 5 due 09/04/2006	AA	Fe25,05		ES0357080045
EUR500 mil fltg rate nts ser 4 due 02/08/2008	AA	Fe15,05		ES0357080037
EUR8 bil Sr Unsecd/Sub/S-T Debt Domestic fixed income note prog : sub	AA-	Au02,04		
EUR100 mil fltg rate step-up callable sub med-term nts due 06/30/2014	AA-	Ju16,04		ES0257080004
EUR8 bil Sr Unsecd/Sub/S-T Debt Domestic fixed income note prog : S-T debt	A-1+	Au02,04		
BPI Capital Finance Ltd. GTD: Banco BPI S.A.				
EUR250 mil step up callable perp non-cum, non voting gtd fltg pref shares, ser C ser C	BBB	Au21,03		XS0174443449
BPLP CAC Corp. [BBB+/Stable/—]				
BPM Capital I LLC *GTD: Banca Popolare di Milano SCRL*				
EUR160 mil 8.393% non-cum co. pfd secs	BBB	Ju24,01		
BPM Captital Trust I GTD: Banca Popolare di Milano SCRL				
EUR160 mil 8.393% *non cum* trust pfd secs	BBB	Ju24,01		XS0131749623
BPM Securitisation S.r.l.				
EUR1.34 billion floating-rate notes				
Class A (EUR583 mil)	AAA	Ju26,01		XS0132407791
Class B (EUR38.2 mil)	AA+	De01,04	AA	XS0132407874
Class C (EUR19.1 mil)	BBB	Ju26,01		XS0132408252

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Research:

BP PLC

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ISSUER CREDIT RATINGS	
BP PLC	
Corporate Credit Rating	AA+/Stable/A-1+
BP America Production Co.	
Corporate Credit Rating	AA+/Stable/A-1+
BP Corporation North America Inc.	
Corporate Credit Rating	AA+/Stable/A-1+
Burmah Castrol PLC	
Corporate Credit Rating	AA+/Stable/A-1+
Amoco Argentina Oil Co.	
Corporate Credit Rating	AA+/Stable/--
BP Canada Energy Co.	
Corporate Credit Rating	
Local currency	AA+/Stable/--
Corporate Credit Rating	
Foreign currency	AA+/Stable/A-1+
BP Company North America Inc.	
Corporate Credit Rating	AA+/Stable/--
BP Products North America Inc.	
Corporate Credit Rating	AA+/Stable/--

AFFIRMED RATINGS	
BP PLC	
Sr unsecd debt	
Foreign currency	AA+
CP	
Foreign currency	A-1+
BP America Production Co.	
Sr unsecd debt	
Local currency	AA+
Sr secd debt	
Local currency	AA+
Sub debt	
Local currency	AA
BP Corporation North America Inc.	
Sr unsecd debt	
Local currency	AA+
BP Overzee B.V.	
Burmah Castrol PLC	
Sr unsecd debt	
Foreign currency	AA+
Short-Term Debt	
Foreign currency	A-1+
Amoco Argentina Oil Co.	

Sr unsecd debt
Local currency AA+
BP Canada Energy Co.
Sr unsecd debt AA+
BP Company North America Inc.
Sr unsecd debt
Local currency AA+
BP Products North America Inc.
Sr unsecd debt
Local currency AA+

Business Profile:
Superior
Financial Policy:
Conservative
Debt Maturities:
At Dec. 31, 2001 (*mil. $*)
2002 9,018
2003 1,460
2004 641
2005 1,566
2006 and beyond 7,091
Collateralization:
Not significant
Bank Lines:
Bank lines include $34 billion in unused committed facilities at Dec. 31, 2001, expiring in 2002.
Corporate credit rating history:

Jan. 5, 1999	AA+/A-1+
July 23, 1996	AA/A-1+

Rationale

The ratings reflect BP PLC's extremely strong, geographically diverse business portfolio; solid financial profile; and fairly conservative financial policy. BP's key competitive strengths include:

- A massive reserve base -14.6 billion barrels of oil equivalent (boe) at year-end 2001—especially in North America and the North Sea, with promising developments in the Gulf of Mexico. The reserve life is adequate, at 11.7 years; replacement rates are strong (156% on average over 1999-2001 on an internal basis); and finding and production costs ($3.43 per boe on the same basis) are competitive;
- Robust 2000-2005 production growth (6.5% annually, as was achieved in 2001)—based on promising prospects in South America, West Africa, and the Caspian Sea—and an excellent position from which to serve the large, growing, and profitable U.S. gas market; and
- Profitable, very large, and sophisticated refining and marketing (R&M) assets across Europe (BP became market leader in Germany, with the acquisition of a 51% stake in Veba's assets, completed Feb. 1, 2002) and the U.S. BP's first-quarter 2002 refining throughput and oil-product marketing sales were 3.0 million boe per day and 4.0 million boe per day, respectively.

Despite expected lower crude and gas prices and refining margins in 2002 compared with 2000-2001, BP's credit measures should remain adequate for the rating category after disposals of $1 billion-$2 billion annually over the next few years and profit improvements of $1.4 billion in 2002. Lease-adjusted funds from operations (FFO) of $17.4 billion represented an adequate 73.3% of year-end 2001 net debt and amply covered capital expenditures of $12.8 billion (capital expenditures of $12 billion-$13 billion are estimated for subsequent years). In 2001, underlying EBIT totaled $19.8 billion (74% from exploration and production (E&P)), covering financial fixed charges 7.5 times (x) and fueled by still-healthy prices for U.S. natural gas and international crude oil, and by increased cost cutting. Net debt at March 31, 2001, was $22.9 billion, before adjusting for operating leases, and the quarter's EBIT interest coverage was an adequate 8.4x.

Outlook

The ratings will continue to be supported by BP's superior business positions, ongoing cost savings, rising production levels, and prudent financial policies. The currently healthy FFO-to-debt coverage ratio is expected to be maintained.

Business Description

BP is the world's third-largest private oil and gas group, with leading operations in Europe, the Americas, and Australasia, as well as a growing presence in East Asia (in 2000, BP acquired 2.2% of the large Chinese energy groups Sinopec and PetroChina, for a combined $984 million) and Russia (notably through Sidanco; in April 2002, BP increased its stake in Sidanco to 25% plus one share, from 10% previously, for $375 million).

At year-end 2001, 26.5% of the group's $101 billion capital employed was in Europe and 43.8% in the U.S. Fifty-nine percent was in upstream (E&P) operations, 24.5% in R&M, and 11.9% in chemicals (a notable decrease from 16.0% at year-end 1999, owing to capital-expenditure restraint, asset sales, and the strong growth in consolidated capital employed during the period). However, the relative contributions of these three business segments to operating earnings (about 70%, 20%, and 10%, respectively, under normalized price conditions) highlight the structurally high, though volatile, contribution from upstream operations.

The integration of key E&P operations with R&M activities and base-petrochemicals assets provides BP with some hedge against price fluctuations for crude oil and chemicals (see table 1). In line with its aims, BP is likely to remain short in refining throughputs compared with both hydrocarbon production (with a ratio of 0.86x in 2001) and marketing sales (0.77x).

Table 1 BP PLC Consolidated Operating Statistics						
	--Year ended Dec. 31--					
	Replacement cost operating profit					Operating capital employed (%)*
(Mil. $)	2001	2000	1999	1998	1997	2001
E&P	14,408	16,710	4,17[illegible]	7,385	7,073	59.1
Gas & Power¶	521	571	160	211	56	2.8
R&M	4,830	4,558	2,661	2,297	1,708	25.0
Chemicals	242	1,036	1,100	1,530	1,664	12.1
Main activities	20,091	21,876	8,[illegible]	6,895	11,207	100.0
Other operations and corporate	(483)	(622)	(836)	(374)	(594)	1,850
Group total	19,608	21,253	8,521	10,683	10,944	101,1??

*In millions of dollars for "Other operations and corporate" and "Group total." ¶Before 1998; Data merged into the E&P segment.

Business Profile:

E&P.

BP has vast E&P operations spanning 29 countries, with production in 23. Excluding associated companies, consolidated reserves of 14.6 billion boe (at year-end 2001)--equally split between crude and natural gas--are concentrated in Alaska and the onshore and offshore basins of the lower 48 states, as well as in the U.K. North Sea. BP is the largest hydrocarbon producer in both the U.S. and the U.K. (42% and 14% of the group's year-end 2001 proven reserves, respectively). It accounts for about 25% and 18% of U.K. crude and gas production, respectively; however, BP's U.K. reserve life is considerably lower than the group average (7.3 years versus 12.9 years, respectively). The group has strong and growing operations in the Gulf of Mexico, Trinidad, North Africa, offshore West Africa, the Middle East (where it is trying to enter the Saudi and Kuwaiti markets as they open up to foreign investment), and the Caspian Sea. The acquisitions of Amoco and Arco lifted gas production to 8.6 billion cubic feet per day in 2001, from 1.7 billion cubic feet per day in 1998. The group's gas reserves have a longer life than its crude reserves (13.9 years versus 12.0 years, respectively, compared with the group average of 11.7 years for gas and crude combined at year-end 2001); BP 's gas production growth should outpace that of its oil output, supported by 43 trillion cubic feet of proven reserves at year-end 2001.

In 2001, BP fully replaced production for the eighth consecutive year, with a particularly high ratio of 191%, and finding and development costs remained below a competitive $4 per boe, a level that Standard & Poor's does not expect BP to surpass in the coming years. Production from BP's relatively mature U.K. and U.S. crude reserves should stabilize or grow moderately in the future, given the large field developments in the North Sea and the Gulf of Mexico; in the Gulf of Mexico, which in 2001 represented 19% of consolidated production (including a record 13% for deepwater fields only), BP has the largest acreage of any company and participates in the vast majority of large-scale projects under development. In 2001, Gulf of Mexico deepwater crude production reached a strong 243,000 barrels per day (bpd) and could reach 400,000 bpd by 2003.

Reserve bookings and production increases in other areas–including West of Shetland, the Gulf of Mexico, Trinidad (where no less than 16% of BP's year-end 2001 proven reserves are located), Australia, Colombia, Algeria, and Angola–should help BP to more than replace reserves and to raise production. During 2000-2001, however, BP's developed reserves as a proportion of total proven reserves decreased to 57% from 68%, pointing to significant development spending needs in the next few years.

BP has uniquely strong positions from which to supply the U.S. natural-gas market, which is the largest in the world and should continue to experience favorable pricing (Standard & Poor's medium-term Henry Hub price expectation is $2.25 per million cubic feet). BP's production from and proven reserves in North America and Trinidad are significantly higher than those of any of its peers. BP ships its production from Trinidad to the U.S. in the form of liquefied natural gas (LNG) through its local, 34%-owned liquefaction plant, which is currently the sole liquefaction plant in the Atlantic basin aside from the Bonny, Nigeria, plant, and which will start one new liquefaction train in 2002 and 2003 each. BP's worldwide natural-gas production, which is expected to grow by a strong 8%-10% on average until 2005, should exceed a massive 11.7 billion cubic feet per day at the end of the period, as production grows rapidly in the Gulf of Mexico, the lower 48 states, and in Trinidad. In the Gulf of Mexico, where BP has made a string of large discoveries in recent years, gas production increased by 34% in 2001 to 1.2 billion cubic feet per day, contributing about 10% of BP's worldwide natural-gas production.

The group's 5.5% average annual total hydrocarbon production growth target until 2005 includes 8%-10% growth for gas alone. Although ambitious, this average annual production objective, the achievement of which in 2001 took into account a minor positive impact from net acquisitions, is achievable for the next few years given the group's attractive exploration and development portfolio. It will, however, require steady capital spending, in line with management's current budget. While production grew by only 0.75% in first-quarter 2002 year-on-year, this does not call into question the group's 5.5% growth objective for the full year, since growth in 2002 is expected to be back-ended. Geographic diversification away from mature onshore U.S. and North Sea basins should also increase, as a result of a number of large projects coming onstream outside these regions, notably in Angola's blocks 15 and 17 and in the Gulf of Mexico. Gas' share of BP's total hydrocarbon production, which increased from one-third before the Amoco and Arco acquisitions to 43.5% in 2001, should exceed 45% by 2005; it will then decline, since after 2005, BP's total hydrocarbon production growth will be driven by crude rather than gas. In 2001, no non-OECD country represented more than 5% of consolidated production, except Trinidad and Tobago (about 7%), and exposure to the politically volatile Middle East is lower for BP than for other majors like Royal Dutch Shell Group of Companies (AA/Stable/A-1+), TotalFinaElf S.A. (AA/Stable/A-1+) and ENI SpA (AA/Stable/A-1+). Nevertheless, for crude only, Egypt, where BP produces 30% of the country's crude production in a joint-venture with the national oil company, represented more than 5% of the group's consolidated production in 2001, while Indonesia and Trinidad represented 6.0% and 12.2% of consolidated 2001 gas production. In addition, Trinidad represented a high 16% of group total reserves at year-end 2001, although gas production and liquefaction in Trinidad involves little political or fiscal risk. BP has strong potential for growth in West Africa's deep offshore–notably in Angola–and in North Africa, particularly in Algeria and Egypt.

Management's production growth targets are coupled with intense cost-cutting measures and operating improvements, including the disposal of underperforming assets and the introduction of innovative risk- and incentive-sharing contracts with engineering clients. Consequently, returns on projects under development exceed cost of capital even at depressed Brent crude prices of about $11 per barrel, which is well below Standard & Poor's expectations of a $16 per barrel midcycle price. Lifting costs, before production taxes, are expected to remain at very competitive levels of about $2.88 per boe, as in 2000, down 18% on the 1998 figure.

Average finding and development costs (excluding sales and purchases of reserves in place), which were a competitive $3.43 per boe over 1999-2001, are not expected to exceed $4 per boe in the next few years. Generally, BP's average worldwide crude price realization is about 10%-15% lower than the Brent benchmark. Divisional EBIT decreased by 8% in 2001 to $14.5 billion, compared with $15.7 billion in 2000, as the 15% decrease in crude price realizations more than offset the combination of a 13% increase in natural-gas price realizations, a full-year contribution from Arco, and slight production growth. However, Standard & Poor's expects 2002 EBIT to be significantly lower than in the two previous years: Fourth-quarter 2001 and first-quarter 2002 EBIT ($2.4 billion for each) are more representative of BP's future performance at normalized price levels, since the Brent and Henry Hub indicators were less than 10% above Standard & Poor's standard assumptions (although European gas prices, which were still high during the period, did start to decline in first-quarter 2002); at $2.4 billion, E&P operating income remains healthy, enabling the division to both self finance capital expenditures--as required by production growth targets--and contribute to consolidated free cash flow. This picture is not significantly altered by the U.K. government's recent announcement that it will increase North Sea taxes, which will have an impact on BP of about $200 million annually from 2003, based on first-quarter 2002 prices.

None of the figures mentioned in the preceding paragraphs includes BP's share of associated undertakings, with year-end 2001 proven reserves of 1.7 billion boe located essentially in Abu Dhabi (under concessions) and in South America, notably through 60%-owned, but equity-consolidated, Pan American Energy LLC (PAE, CCC+/Negative/--), which operates mainly in Argentina; BP's exposure to Argentina through PAE is less than 2% of its global oil and gas production, however). Standard & Poor's views the financial and political risk associated with the long-term concessions in Abu Dhabi as moderate, but the price and fiscal risks associated with PAE as high given the current economic and fiscal uncertainty in Argentina.

Midstream, BP's most prominent pipeline stakes are 50%, 100%, and 10%, respectively, of the large Trans Alaskan (capacity of 2 million bpd), Forties (1 million bpd), and Interconnector (20 billion cubic meters per year) systems. BP also owns interests in large LNG producers in Abu Dhabi (10%) and Trinidad (34%).

Table 2 BP PLC Consolidated E&P and R&M Operating Statistics*

	--Year ended Dec. 31--				
	2001	2000	1999	1998	1997
E&P					
Total proven reserves (mil. boe)	14,624	13,594	12,363	12,649	12,849
% oil	49	48	53	58	59
% developed	57	63	68	69	65
% Europe	17	20	20	18	19
% U.S.	42	42	48	47	49
Three-year internal reserve replacement rate (%)	151	138	134	149	N.A.
One-year internal reserve replacement rate (%)	173	163	112	132	160
Production (mil. boe)	1,248	1,095	1,050	1,012	1,018
% oil	56	57	64	64	63

Reserve life (years)	11.7	12.4	11.8	12.5	12.6
Three-year finding and development costs ($/boe)	3.43	3.71	4.09	4.28	N.A.
One-year finding and development costs ($/boe)	3.68	3.29	3.21	4.7	4.22
Exploration spending (mil. $)	1,102	1,295	848	1,523	1,791
Development spending (mil. $)	6,858	4,563	2,915	4,771	5,082
Total E&P investments (mil. $)	8,224	23,160	4,312	6,472	7,147
Lifting costs ($/boe)	2.86	2.7	2.83	3.54	3.33
Consolidated debt/reserves ($/boe)	1.37	1.47	1.37	1.31	1.22
Average crude realization ($/barrel)	22.5	26.8	16.7	12.1	18.3
Average U.S. gas realization ($/mcf)	3.99	3.72	2.06	1.8	2.2
R&M					
Distillation capacity (excl. mothballed) (000 bpd)	3,203	2,801	2,815	2,937	3,027
Refinery throughputs (000 bpd)	2,928	2,541	2,711	2,867	2,812
Europe (%)	32	32	31	31	30
U.S. (%)	55	53	55	56	57
Rest of the world (%)	13	15	14	13	13
Throughputs/distillation capacity (%)	95	91	96	98	93
Marketing sales (000 bpd)	3,756	3,186	3,137	3,063	2,924
Europe (%)	30	32	33	33	31
U.S. (%)	52	48	48	48	49
Rest of the world (%)	17	19	19	20	20
Marketed volumes/refining capacity (x)	1.17	1.14	1.11	1.05	0.97

*All figures exclude associate companies, except otherwise stated. boe–Barrels of oil equivalent. mcf–Million cubic feet. bpd–Barrels per day. N.A.–Not available.

R&M.

BP is the world's third-largest refiner and marketer of oil products, with 2.9 million bpd of refining capacity (after several divestitures during the year) and 26,800 retail sites worldwide at year-end 2001.

About half of the group's 2001 refining throughputs and marketing sales were in the U.S., and 35% were in Europe. BP's business positions in both Europe and the U.S. were strengthened significantly by the 2000 acquisition of Arco's highly profitable U.S. West Coast assets, the $1.5 billion buyout of ExxonMobil's 30% share of its European fuel joint venture with BP (completed Aug.1, 2000), and the 2002 $2.48 billion acquisition of a 51% stake in Veba AG's German assets (the seller, E.ON, having a put option on the remaining 49%, which, in May 2002, it said it might exercise on July 1, 2002 for $3.05 billion). Although BP 's refineries are among the largest and most sophisticated in each of its regions of operation, the return on capital has lagged that of the company's E&P segment because of the refineries' locations in extremely competitive markets, with the notable exception of two large, formerly Arco-owned U.S. West Coast refineries (more than 400,000 bpd distillation capacity combined). These two facilities have historically ranked among the lowest-cost producers in the region and enjoy structurally high profitability because of the U.S. West Coast's environmental regulations and insulation from imports and transport costs. The Veba deal will increase BP's refining capacity by more than 10% to 314,000 boe per day (taking into account 100% of Veba's capacity, but not factoring in the required disposal of 45% of Veba's stake in its Bavarian refinery), causing a slight shift in the proportions of BP's refining capacity located in the U.S. and Europe in favor of the latter.

In marketing, since the completion of the Veba deal, BP has been Europe's largest player (7,500 service stations at year-end 2001), along with ExxonMobil and Shell. Adding about 3,000 Aralbranded Veba sites, BP will enjoy--even after the modest divestitures required by Germany's antitrust authorities, the equivalent of a 4% market share--a European fuel market share exceeding 15% on average (up from 6% in 1999, and compared with Shell's 14% and TotalFinaElf's 10%), with, in particular, more than 18% in the U.K., Germany, Turkey, and the Netherlands. The group had 15,500 service stations in the U.S. at year-end 2001 (32% company owned), concentrated in the Midwest, East, and Southeast, as well as on the West Coast since the acquisition of Arco's very profitable 1,800-site network (with 18% market share on the West Coast as a whole and 26% in California alone). In the rest of the world, BP had approximately 3,800 service stations at year-end 2001, with particular strengths in the large markets of Australia, South East Asia, and South Africa. The group is pushing strongly to increase convenience-store sales of non-oil products, which reached $3.2 billion in 2001, almost double the 1999 level ($1.7 billion).

In lubricants, the $4.8 billion acquisition of Burmah Castrol PLC (AA+/Stable/A-1+) in 2000 added this company's very strong Castrol lubricant brand and leading global positions--with excellent positions in emerging markets--to BP's product portfolio; the Castrol brand is being introduced throughout BP's retail network.

Despite extremely competitive non-West Coast U.S. and northwestern European markets, and thanks to high retail profitability, geographic diversity, a refocusing on advantaged assets, and ongoing cost cuts, divisional 2001 EBIT of $4.83 billion was up 6% on the comparable 2000 figure, as higher retail margins and volumes and the first full-year contribution of Arco's assets (which in 2000 were consolidated only starting in April) more than offset weaker refining margins globally. Synergies of $260 million (pretax) are expected from the Castrol acquisition by 2003, after integration costs of $390 million charged to the 2000 accounts. Synergies of at least $200 million (after restructuring costs of $200 million) are expected from the combination of BP's German assets and those of Veba, with the latter having generated EBITDA of $656 million on average during 1998-2000. However, 2002 divisional EBIT is likely to be significantly down on 2001's, given the crumbling of refining margins in Europe in January-May 2002 and first-quarter EBIT of only $287 million.

R&M capital spending was kept within $1.7 billion-$2.0 billion during 1996-1999, and increased to only $2.4 billion in both 2000 and 2001, despite the increased scope of activity following the Amoco and Arco acquisitions. This restraint--which is expected to continue--together with ongoing disposals, has reduced overall group exposure to this segment.

Chemicals.

BP's chemicals unit (2001 revenues of $11.5 billion) is focused mainly on Europe and the U.S., with a modest but growing presence in Asia. It benefits from leading positions in olefins, polyolefins, purified terephthalic acid (PTA), and polyesters. Bulk-chemicals production is generally high risk, since price swings can be very volatile. In both 1999 and 2001, this division's EBIT generation was hurt heavily by a poor environment; EBIT in 2001 was only $242 million. The company's focus on the most advantageous and profitable operations, combined with the cyclical rebound in chemicals volumes and prices--envisaged by late 2002--should lead to a strong improvement in earnings. As in the past, however, the chemicals division will not enhance BP's overall business and financial

■ Financial Profile

Financial Policy: Conservative

Management intends to maintain the ratio of net debt to permanent capital (unadjusted for operating leases) within the 25%-35% range (33% expected at March 31, 2002, compared with 29.5% at year-end 2001, due notably to the Veba-related cash disbursement) and the dividend payout at 60% of underlying earnings restated at midcycle price conditions. Both targets are based on figures adjusted for the FRS19 "Deferred Tax" accounting standard (other figures in this report are not adjusted for FRS 19, the application of which, at Dec. 31, 2001, would have resulted in $9.05 billion reduction in equity and a $1,358 million increase in 2001 taxes). These objectives, which Standard & Poor's believes are compatible with the company's growth targets, should provide a healthy balance between strong creditor protection and adequate shareholder returns. The $10 billion disposal program announced in 1999 was completed by year-end 2001; profit improvement of $6.1 billion was realized over 1999-2001 (compared with $5.8 billion expected), of which $2 billion in 2001 alone; a further $1.4 billion in cost savings and volume growth is expected for 2002. The group bought back $3.3 billion worth of its own shares in 2000 and 2001 combined. Further repurchases were not effected during the first quarter of 2002; any future repurchases are expected to remain compatible with the maintenance of credit ratios at levels at least as high as those recorded in 2001.

Profitability.

The massive $5.8 billion in cost synergies targeted over 1999-2001—equivalent to a five-to-six percentage-point increase in after-tax returns on capital employed—and the $2 billion target for 2001 alone were all achieved. The surpassing of expectations regarding the amount and timing of cost synergies from the mergers with Amoco and Arco illustrates BP's resolute cost-cutting policy. Another $1.4 billion in pretax cost savings is expected for 2002.

In 2000, BP's pretax return on capital employed (excluding the fixed-asset revaluation adjustment and goodwill resulting from the Arco and Castrol acquisitions) surged to 23%, from under 15% and 9% in 1999 and 1998, respectively. In 2001, it remained close to 20%—a strong level—despite a weaker market environment. This robust performance reflected fairly steady EBIT of $16.1 billion (including the share of profits from joint ventures and associated undertakings)—compared with $17.8 billion in 2000—based on sustained high crude and U.S. gas prices until the fall, and ongoing cost cutting and synergies. Seventy-six percent of 2001 EBIT was generated by E&P operations. Despite expected lower crude and gas prices in 2002 compared with 2000-2001, BP's credit measures should remain adequate for the rating category. On the basis of constant economic conditions, annual earnings growth is expected to reach or exceed 10% in the future, outpacing growth in capital employed of about 4%-6% per year; this would result in further gains in return on capital employed.

In 2001, EBIT covered interest expenses 11.7x, fueled by still-healthy U.S. natural-gas and international crude prices and increased cost cutting.

While chemicals earnings will remain highly volatile in the future, and crude and natural-gas prices should be lower starting in 2002 than they were in 2001 on average, Standard & Poor's expects R&M and E&P operations to continue to enjoy robust cash flow generation in a midcycle environment.

Cash flow protection.

Lease-adjusted FFO of $17.4 billion in 2001 represented 73.3% of year-end net debt—which is adequate for the current rating level—and amply covered capital expenditures of $12.9 billion. Upstream operations should absorb about 60% of gross capital spending of $12 billion-$13 billion on average over 2001-2003 (before about $1.5 billion of annual asset disposals, so that FFO and ongoing disposals of $1 billion-$2 billion a year on average are expected to fully finance capital expenditures and dividends), with deepwater oil and core oil operations accounting for 18% each and core gas and emerging gas operations 11%-12% each. R&M operations (focused on further strengthening the retail network) and chemicals should absorb about 20% and 15%, respectively, of annual capital expenditures over the period. In 2001, E&P, R&M, and chemicals represented 62%, 17%, and 14% of group capital expenditures, respectively. Standard & Poor's does not expect capital spending to surpass announced levels, which exceed those of Shell and ExxonMobil—both large, though slower-growth, companies. However, environmental capital expenditures, which rose to $423 million in 2001 from $298 million in 2000, should further increase in the near term; in 2001, environmental operating expenditures decreased to $575 million from $653 million a year earlier.

Capital structure and financial flexibility.

Lease-adjusted net debt (before application of FRS 19) remained at moderate levels through the difficult 1997-1999 period, being each year under 27% of permanent capital, and declined to only 24% at year-end 2000 and further to 21% at year-end 2001, reflecting management's prudent approach to leveraging. Net debt (unadjusted for operating leases) should remain within 25%-35% of permanent capital (32% at March 31, 2002) and is expected to remain almost exclusively in dollars. Financial flexibility benefits from $3.4 billion in unused committed bank lines at year-end 2001. BP's liquidity and flexibility are not weakened by contingent requirements (which for major international oil and gas groups may include the need to support project debt or any nonconsolidated debt, rating triggers, covenants, or potential needs to post collateral) to any significant extent. At year-end 2001, BP's share of third-party financing contracted by joint-ventures and associated undertakings was a combined $1.6 billion. Decommissioning and environmental provisions totaled $6.3 billion, while unfounded pension plans and other postretirement benefits amounted to $4.4 billion, compared with $5.1 billion and $4.3 billion, respectively, at Jan. 1, 2001; given more than $150 billion in total assets, these amounts are significant but fully manageable at current rating levels. Like a number of integrated oil companies, the group restricts external insurance to situations where it is needed for legal or contractual reasons. Structural subordination of parent-company liabilities to subsidiary liabilities is moderate, given the expected maintenance of a ratio of priority liabilities over consolidated assets in the mid-20s--a relatively moderate ratio that is mitigated by the considerable diversity of operations worldwide.

Table 3 BP PLC Financial Statistics					
	--Year ended Dec. 31--				
(Mil. $)	2001	2000	1999	1998	1997
Revenues	174,218	148,062	83,566	68,304	91,760
EBITDA	24,950	25,284	14,013	11,997	16,196
EBIT	16,135	17,756	8,894	6,323	10,714
Net financial fixed charges*	2,213	2,340	1,698	1,614	1,469
Net income	8,008	11,868	5,006	3,283	5,824
Funds from operations (FFO)	17,434	14,365	9,195	8,261	12,937
Capital expenditures¶	12,214	10,101	6,534	8,431	8,600
Cash flow after capital expenditures	5,220	4,264	2,661	(170)	4,337
Disposals (net of acquisitions)	810	3,894	1,392	2,165	(1,156)
Dividends paid	4,827	4,415	4,135	2,408	2,437
Free cash flow§	6,191	839	632	182	5,733
Equity	74,973	73,980	45,403	44,645	42,848
Total financial debt**	21,417	21,190	14,544	13,755	12,877
Cash and cash equivalents	1,358	1,170	1,331	405	355
Net financial debt**	20,059	20,020	13,213	13,350	12,522
Net financial debt incl. operating leases (ND)	23,787	23,916	15,961	16,531	15,703
Total assets	141,158	143,938	89,561	84,915	85,947
ND/permanent capital (%)	21.1	21.3	22.5	23.0	22.6
ND/(oil and gas reserves) ($/boe)	1.63	1.76	1.29	1.18	0.97
FFO/ND (%)	73.3	60.1	57.6	50.0	82.4
Pretax net fixed-charge coverage (x)	7.5	7.8	5.4	3.3	6.9
Pretax return on net perm. capital (%)	16.9	22.8	15.1	8.9	33.1

*Including capitalized interest. ¶Including exploration expenses. §FFO - (capital expenditures + net acquisitions + dividends). **Unadjusted for the capitalization of operating leases. Operating-lease commitments are assumed to be identical at year-end 1997 compared with year-end 1998. N.A.--*Not available.*

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ATLANTIC RICHFIELD CO./BP AMOCO PLC

Analysts: Jill Unferth, New York (1) 212-438-7815, Emmanuel Dubois-Pelerin, Paris (33) 1-4420-6673

VARIOUS RATING ACTIONS

CREDIT PROFILE

ISSUER CREDIT RATINGS

Atlantic Richfield Co.	
Corp credit rtg	AA+/Stable/A-1+
Union Texas Petroleum Holdings Inc./ARCO Pipeline Co./Anaconda Co.	
Corp credit rtg	AA+/Stable/—
Vastar Resources Inc.	
Corp credit rtg	BBB+/Watch Pos/A-2
BP Amoco PLC/BP Amoco Corp./British Petroleum Co. PLC	
Corp credit rtg	AA+/Stable/A-1+
BP Amoco Co./Standard Oil Co./Standard Oil Co. Indiana/Carborundum Co./Amoco Oil Co./Amoco Canada Petroleum Co. Ltd./Amoco Argentina Oil Co.	
Corp credit rtg	AA+/Stable/—

REVISED RATINGS

Atlantic Richfield Co.	
Sr unsecd debt	AA+
Pref stk	AA-
CP	A-1+
Union Texas Petroleum Holdings Inc.	
Sr unsecd debt	AA+
Pfd stk	AA-
Sub shelf debt	AA (prelim)
ARCO Pipeline Co.	
Sr unsecd debt	AA+
ARCO British Ltd.	
CP (Gtd: Atlantic Richfield Co.)	A-1+

April 18, 2000 Standard & Poor's raised the ratings for Atlantic Richfield Co. (ARCO) and related entities, with the exception of 82% ARCO-owned Vastar Resources Inc. The ratings on Vastar Resources remain on CreditWatch with positive implications, while the ratings on ARCO and all other related entities are removed from CreditWatch with positive implications, where they were placed on March 31, 1999. Also, Standard & Poor's affirmed its ratings for BP Amoco PLC and related entities.

The ratings actions follow completion of BP Amoco's protracted $27 billion all-stock acquisition of ARCO, which creates the world's third-largest oil company. In addition, Standard & Poor's expects BP Amoco to attain 100% ownership of Vastar in the very near term, based on the company's March 16, 2000 announcement that it would tender for all Vastar common stock not owned by ARCO upon closure of the merger. Upon completion of the purchase of the remaining Vastar shares by BP Amoco, the ratings on Vastar will be upgraded to those of ARCO. Although BP Amoco has neither legally assumed nor guaranteed the obligations of Arco and Vastar, Standard & Poor's be- lieves these companies to be core to Amoco and that BP Amoco will h these obligations as their own.

Ratings for London-based BP Am reflect the company's extremely strong geographically diverse business portf relatively conservative financial pr and policies; enormous, internationall versified, and medium-lived oil and n ral gas reserve base; strong res replacement rates; expectations for st medium-term production growth f U.S. Gulf of Mexico, South America, Africa, and Caspian Sea prospects; petitive production costs; and profit very large, and sophisticated refining marketing assets in the U.K. and the

OUTLOOK: STABLE

Prudent financial policies, an improve set base, rising production levels, and ther anticipated cost savings should e BP Amoco to maintain credit quali current levels.

BP AMOCO PLC

Analyst: Emmanuel Dubois-Pelerin, Paris (33) 1-4420-6673

AFFIRMED

CREDIT PROFILE

ISSUER CREDIT RATINGS	
BP Amoco PLC/Amoco Corp./British Petroleum Co. PLC	
Corp credit rtg	AA+/Stable/A-1+
Amoco Argentina Oil Co./Amoco Co./Amoco Oil Co./Standard Oil Co./Standard Oil Co. Indiana/Carborundum Co.	
Corp credit rtg	AA+/Stable/—
Amoco Canada Petroleum Co. Ltd.	
Corp credit rtg	
Local currency	AA+/Stable/—
Corp credit rtg	
Foreign currency	AA+/Stable/A-1+

BUSINESS PROFILE:
Well above average

FINANCIAL POLICY:
Conservative

DEBT MATURITIES:	
1999	$2,736 mil
2000	$993 mil
2001	$940 mil
2002	$1,868 mil
2003 and beyond	$5,336 mil

COLLATERALIZATION:
Not significant

BANK LINES:
$2.8 billion of unused committed facilities at year-end 1998, expiring in 2001

CORPORATE CREDIT RATING HISTORY:	
Jan. 5, 1999	AA+/A-1+

RATIONALE The ratings on BP Amoco PLC reflect the company's extremely strong and geographically diverse business portfolio, solid financial profile, and relatively conservative financial policies.

BP Amoco's key competitive strengths include:

- A massive reserve base of about 12.6 billion boe at year-end 1998, a healthy reserve life of 12.5 years, recently strong replacement rates, and competitive production costs;
- A strong North American reserve base—with promising developments in the Gulf of Mexico—and solid operations in the North Sea;
- Promising prospects in high-potential regions, such as South America, West Africa, and the Caspian Sea;
- Significant medium-term production growth potential; and
- Ownership of profitable, very large, and sophisticated refining and marketing assets in the U.K. and U.S.

The merger of British Petroleum PLC and Amoco Corp. was completed in record time and will deliver the expected $2 billion in cost savings in the first full year of operations.

On April 1, 1999, BP Amoco announced the all-stock purchase of Atlantic Richfield Co. (ARCO) for $26.8 billion and the assumption of about $7.7 billion of ARCO's debt. If the merger is completed—which is expected by year end—prospective operating benefits will be significant—notably in *Alaska*—even if anti-trust regulators require the sale of important operations. Furthermore, BP Amoco would benefit from ARCO's complementary oil-producing interests in the North Sea and the Gulf of Mexico. ARCO would also provide the group with access to Asia's energy markets. In refining and marketing, ARCO's strong and profitable operations on the U.S. West Coast would complement BP Amoco's strength on the East Coast. Annual savings from the merger could total $1 billion.

Nevertheless, BP Amoco's capital structure would be impaired by the assumption of Arco's debt and pro forma financial measures would be weak for the current rating levels. Despite somewhat low profitability measures in 1998, targeted profit improvements of $4 billion by 2001 should enable the group's main financial measures to rebound sharply to levels in line with the current ratings.

OUTLOOK: STABLE

Cost savings, rising production levels, and prudent financial policies should enable BP Amoco to maintain credit quality at c rent levels.

BUSINESS DESCRIPTION

BP Amoco is one of the world's three l est private oil and gas groups, with ex sive operations in Europe, the Ameri and Australasia, as well as a growing p ence in East Asia. About 45% of capit employed in Europe and a third in the l Vertical integration shows a healthy l ance between rising production of 2.8 r lion boe per day, distillation capacity of million barrels per day (bpd), and mar ing sales of 3.1 million bpd. The integ tion of key exploration and product (E&P) operations with refining and m keting activities (R&M) and base pet chemicals assets provides BP Amoco w some hedge against price fluctuations oil and chemicals (*see Table 1*). The con bution of the key E&P division to cons dated earnings before interest and ta (EBIT)—62% (before exceptionals) on erage over 1996-1998—matched E& share of group operating-capital e ployed; the same was true for R&M (ab 23%) and chemicals (about 15%).

BUSINESS PROFILE: WELL ABOVE AVERAGE

E&P. BP Amoco has vast E&P operatio With consolidated reserves of 12.6 billi boe at year-end 1998, of which 58% v oil and 69% was developed) located in countries. The current reserve base highly concentrated in the U.S. (47%) a the U.K. (18%), both countries in wh BP Amoco is the largest producer of cr oil and natural gas. The group is also largest private producer of natural gas North America, with average daily sales 5.3 billion cubic feet in 1998. Reserve l is healthy, at 12.5 years based on 19 production. The internal reserve reple ment rate averaged a very satisfact

127% over 1996-1998, but finding and development costs were subpar. Over 1996-1998, the relatively mature U.K. and U.S. reserves (in particular, the giant Prudhoe Bay field, which accounts for 9% of the group's worldwide reserves) decreased by an annual average of 3% and 6% respectively, and production from the U.S. declined by about 6% a year. Reserve bookings and production increases in other areas, however—including West of Shetland, the Gulf of Mexico, Trinidad and Tobago, Australia, Colombia, Algeria, and Angola—have helped BP Amoco to more than replace reserves and to maintain production levels.

The group's ambitious target of raising production by 25% compared with the 1998 level (notably in gas in the short term, and in crude starting in 2001) while maintaining reserves is achievable given BP Amoco's attractive exploration and development portfolio, notably West of Shetland and in the Gulf of Mexico, Australia, Venezuela, Azerbaidjan, Algeria, and Angola. Geographic diversification away from onshore U.S. and the North Sea should also increase as a number of large projects come onstream outside these regions. Gulf of Mexico crude production almost doubled over 1996-1998 to 117,000bpd and accounted for 14% of the group's total U.S. crude production in 1998. Total hydrocarbon production could reach 800,000bpd in the next decade. Over the first eight months of 1999, BP Amoco announced four field discoveries in the Gulf of Mexico, with recoverable reserves exceeding a combined 1.3 billion boe (group share). Outside the OECD, BP Amoco's production has grown only slightly in recent years. In 1998, no non-OECD country represented more than 5% of total group production, including Colombia, Trinidad and Tobago (13% of group year-end reserves), and Venezuela. West African deep-offshore potential is significant, notably in Angola. In February 1999, BP Amoco wrote off $200 million of its $571 million highly risky (though limited in size for such a large group) investment in the Russian oil company Sidanco.

Management's production growth targets are coupled with intense cost-cutting measures and operating improvements, including the disposal of underperforming assets and innovative risk- and incentive-sharing contracting with engineering clients. Consequently, projects currently being developed are viable, even at currently depressed Brent crude prices of about $14/barrel. Lifting costs, at $3.54/boe in 1998 before production taxes, are competitive. Further reductions in capital expenditures per boe are needed, however, as reflected in above-average combined finding and development costs of $5.04/boe on average over 1996-1998 on total annual capital spending of about $6.5 billion-$7 billion. The exploration budget will be reduced in the near term. Since BP Amoco's production is skewed toward crude, E&P EBIT will continue to be impacted by the crude-oil price environment, as it was in 1998 (down 57% at $3.1 billion, on crude-oil price realizations down 34%). In the first half of 1999, EBIT increased by 10% year-on-year to $2.4 billion (despite lower crude and natural-gas prices).

BP has concession rights over extensive crude reserves in Abu Dhabi (1.87 billion boe at year-end 1998, excluded from the above reserve figures); however, not all such reserves would be recovered at current production levels. Standard & Poor's views the financial and political risk associated with these long-term concessions as moderate.

The merger with ARCO, if completed, would—depending on possible mandatory divestitures—increase BP Amoco's reserve base by about one-third, to over 17 billion boe. In particular, it would increase the group's U.S. production by about 50%; BP Amoco would be the sole operator of producing fields in the Alaskan North Slope, with a 70% equity share of total production in this province.

Midstream. BP Amoco's most prominent pipeline stakes are 50%, 100%, and 10% respectively of the large Trans Alaskan (2 million bpd capacity), Forties (1 million bpd), and Interconnector (20 billion cubic meters (bcm) a year) systems. BP Amoco also owns interests in large liquefied natural gas (LNG) producers in Abu Dhabi (10%) and Trinidad and Tobago (34%). In terms of distribution, BP Amoco owns 25.5% of Germany's leading gas distribution company, Ruhrgas (unrated), to which it will supply 15bcm of gas over 1998-2012.

R&M. About half of BP Amoco's refining capacity and marketing sales is in the U.S. (eight plants), one-third in Europe (seven plants operated by the BP Amoco-Mobil joint venture), and one-sixth in the rest of the world. Management will continue with its strategy of increasing the ratio of marketing volumes to refining capacity to

Table 1

BP Amoco PLC Operating Statistics

	—Year ended Dec. 31—			
	Replacement cost operating profit			Operating capital employed (% of total)*
(Mil. $)	1998	1997	1996	1998
Exploration & production	3,147	7,285	7,873	62.1
Refining & marketing	2,564	2,292	1,708	21.0
Chemicals	1,100	1,530	1,654	16.9
Main activities	6,811	11,107	11,035	100.0
Other operations and corporate	(374)	(524)	(491)	N/A
Group total	6,437	10,583	10,544	N/A
Net exceptional items	850	511	(703)	N/A
Group total, after exceptional items	7,287	11,094	9,841	N/A

*Operating capital employed for the group's main activities totaled $62,165 million in 1998. N/A—Not applicable.

about 1.5 times (x), from the 1998 level of 1.11x (0.97x in 1996). Over 1996-1998, R&M EBIT generation was a strong $2.19 billion on average—representing about 16% of capital employed—thanks to geographic diversity (despite extremely competitive northwestern European markets), refocusing on advantaged assets, and ongoing cost cuts. The set-up of the Pan-European joint-venture with Mobil in 1996—with average market shares of 12% in main fuels (with 8,400 service stations) and 18% in lubricants—enabled BP Amoco to cut its cost base by $500 million as of 1998. BP Amoco might buy back Mobil's share of the joint venture when Mobil merges with Exxon Corp.

BP Amoco has 16,300 service stations in the U.S., concentrated in the Midwest, East, and Southeast, as well as some 3,600 sites outside of the U.S. and Europe. Although the group's refineries are among the largest and most sophisticated in the U.S., the return on capital has lagged that of other segments because of the refineries' location in extremely competitive markets. Capital spending has been kept within $1.7 billion-$2.0 billion since 1996 (of which $1 billion a year on average to upgrade the refineries)—a welcome move to reduce overall group exposure to this difficult segment. Divisional first-half 1999 EBIT of $956 million, while down by 31% compared with first-half 1998, showed a degree of resilience within a sharply deteriorated environment. The acquisition of ARCO would give BP Amoco stakes into two large West Coast refineries that have historically ranked among the lowest-cost producers in the region. The profitability of these refineries has generally been among the best in the U.S., because of the region's insulation from imports, transport costs, and environmental regulations. In addition, ARCO has a 26% share of California's retail market and a total of over 1,700 service stations on the U.S. West Coast.

Chemicals. BP Amoco's chemicals unit, with 1998 revenues of $9.7 billion, is focused mainly on Europe and the U.S., with a modest but growing presence in Asia. It benefits from British Petroleum's leading positions in olefins and polyolefins, coupled with Amoco's similarly strong positions in the fast-growth PTA (purified terephthalic acid) and polyesters markets. Bulk-chemicals production is generally high risk, since price swings can be very volatile. In 1998, this division's EBIT generation remained fairly robust—at $1.1 billion, compared with over $1.5 billion in both 1996 and 1997—despite a particularly poor environment. Similarly, first-half 1999 EBIT generation of $474 million, while down 29% year-on-year, was broadly satisfactory. The next cyclical rebound in chemicals volumes and [
while not envisaged before 2001, s
strongly improve earnings.

FINANCIAL PROFILE

Financial policy: Conservative. Amoco's range of very strong inte[
operations, worldwide geographic
ence, and tight focus on cost reductic
earnings growth, together with m[
ment's relatively conservative pc
should ensure excellent creditworthi[
the foreseeable future. Standard & [

Table 2

BP Amoco PLC E&P and R&M Operating Statistics

	—Year ended Dec. 31—	
	1998	1997
E&P		
Total proven reserves (mil. boe)	12,649	12,849
% oil	58	59
% developed	69	65
% Europe	34	36
% U.S.	50	48
Three-year internal reserve replacement rate (%)	127	N.A.
One-year internal reserve replacement rate (%)	108	142
Production (mil. boe)	1,012	1,018
% oil	64	83
Reserve life (years)	12.5	12.6
Three-year finding and development costs ($/boe)	5.04	N.A.
One-year finding and development costs ($/boe)	5.74	4.77
Exploration spending (mil. $)	1,523	1,791
Development spending (mil. $)	4,771	5,082
Total E&P investments (mil. $)	6,472	7,147
Lifting costs ($/boe)	3.54	3.33
Consolidated debt/reserves ($/boe)	1.18	0.57
Average crude realization ($/bbl)	12.10	18.30
R&M		
Distillation capacity (000 bpd)	2,815	2,937
Refinery throughputs (000 bpd)	2,711	2,867
% Europe	31	31
% U.S.	56	56
% rest of the world	14	13
Throughputs/distillation capacity (%)	96	98
Utilization rate of net rated capacity (%)	98	99
Marketing sales (000 bpd)	3,137	3,083
% Europe	33	33
% U.S.	48	48
% rest of the world	19	20
Marketed volumes/refining capacity (x)	1.11	1.05

All figures exclude associate companies, except otherwise stated. bpd—Barrels per day. N.A.—Not available.

expects BP Amoco's financial measures to improve compared with 1998 levels, fueled by increased cash flow generation, capital-expenditure moderation ($26 billion over 1999-2001, of which $7 billion in 1999), and asset disposals. Management intends to maintain the ratio of net debt to permanent capital (not adjusted for operating leases) within the 25%-30% range and dividend payout at 50% of underlying earnings. This should provide a healthy balance between strong creditor protection and adequate shareholder returns. The group sold its Canadian E&P assets for $ 1.1 billion in August 1999 as part of its $10 billion 1999-2001 disposal plan ($2 billion for 1999 alone); Contributions to this plan from E&P, R&M, and chemicals should be about 40%, over 30%, and 25% respectively.

Profitability and cash flow generation. EBIT and funds from operations fell by 39% and 36% respectively in 1998 (compared with 1997), owing mainly to the depressed crude-price environment throughout most of the year. Return on capital employed was 9%, compared with 14% in 1997.

In the first half of 1999, EBIT declined by a moderate 11% year-on-year to $3.6 billion, and pretax interest coverage, which was 3.7x on a lease-adjusted basis in full-year 1998, was a low 5.5x on an unadjusted basis. While chemicals earnings will remain highly volatile in the future, Standard & Poor's expects R&M and E&P operations to increase their cash flow generation markedly starting in the second half of 1999.

Capital structure and financial flexibility. Lease-adjusted net debt represented a moderate 25.8% of permanent capital at year-end 1998. The lease-adjusted ratio of funds from operations to net debt, at 51% in 1998, is weak for the current ratings, but is expected to improve sharply starting in the second half of 1999. If the acquisition of ARCO goes through, however, BP Amoco's debt will increase by over 50% through the assumption of the U.S. company's debt ($7.7 billion at year-end 1998). This will put additional pressure on BP Amoco's financial measures before sustained free cash flow and large disposals stabilize credit measures in line with the ratings.

Financial flexibility benefits from $2.8 billion in unused committed bank lines. *(This full analysis also will appear in the August 25 edition of Standard & Poor's Credit Analysis Reference Disc (CARD).)*

Table 3

BP Amoco PLC Financial Statistics

	—Year ended Dec. 31—		
(Mil. $)	1998	1997	1996
Revenues	68,304	91,760	102,064
EBITDA	11,494	15,670	15,381
EBIT	6,239	10,614	10,012
Net financial fixed charges*	1,172	1,024	1,085
Net income	3,260	6,030	7,241
Funds from operations (FFO)	7,670	11,975	13,523
Capital expenditures¶	8,431	8,600	8,924
Cash flow after capital expenditures	(761)	3,375	4,599
Disposals (net of acquisitions)	609	(1,158)	882
Dividends paid	2,408	2,437	2,411
Free cash flow§	(3,778)	2,094	1,306
Equity	42,858	42,848	N.A.
Total financial debt	13,350	12,522	N.A.
Cash and cash equivalents	405	355	N.A.
Net financial debt (ND)	12,945	12,167	N.A.
Total debt (TD)**	14,923	14,095	N.A.
Total assets	84,500	85,947	N.A.
TD/permanent capital (%)	23.2	22.1	N.A.
TD/oil and gas reserves (US$/boe)	1.18	0.97	N.A.
FFO/ND (%)**	51.1	84.7	N.A.
Pretax net fixed-charge coverage (x)**	3.7	8.4	N.A.
Pretax return on net permanent capital (%)	8.4	N.A.	N.A.

*Including capitalized interest. ¶Including exploration expenses. §Funds from operations minus (capital expenditures + net acquisitions + dividends). **Adjusted to capitalize operating leases. Operating-lease commitments are assumed to be identical at year-end 1996 and 1997 compared with 1998. EBITDA—Earnings before interest, taxes, depreciation, and amortization. EBIT—Earnings before interest and taxes. N.A.—Not available.

BP Corporation North America Inc.

Consolidated Financial Statements
(UNAUDITED)

March 31, 2005

Basis of Financial Statement Preparation

The consolidated financial statements contained herein are unaudited and have been prepared from the books and records of BP Corporation North America Inc. (the Company). In the opinion of management, the consolidated financial statements reflect all adjustments, consisting of only normal recurring adjustments, necessary for a fair statement of the results for the interim periods. The consolidated financial statements do not include all information and notes necessary for a complete presentation of results of operations, financial position and cash flows in conformity with accounting principles generally accepted in the United States of America.

BP CORPORATION NORTH AMERICA INC.

ADDITIONAL INFORMATION

(UNAUDITED)

Restatements for Reorganization

As more fully explained in the Basis of Presentation note to the December 31, 2004 consolidated financial statements of BP Corporation North America Inc. (the Company), on December 15, 2004, BP America Inc. (BP America) transferred ownership of North America Funding Company to the Company via a capital contribution. Amounts for the three months ended March 31, 2004 have been restated in these financial statements for comparability.

In addition, effective January 1, 2005 segment information has been realigned to reflect the transfer of the aromatics and acetyls operations from the former Petrochemicals segment to the Refining and Marketing segment, and the transfer of the olefins and derivatives operations from the former Petrochemicals segment to Corporate and Other. Segment amounts for property, plant and equipment at December 31, 2004 have been restated in these financial statements for comparability.

Certain other reclassifications have been made to prior year balances in order to conform to current year presentation.

Texas City Refinery Explosion

The Company's Texas City refinery experienced an explosion at its isomerization unit on March 23, 2005. While the financial impact to these financial statements was minimal, it is too early to assess the full financial impact of this incident.

BP CORPORATION NORTH AMERICA INC.

CONSOLIDATED STATEMENT OF INCOME

2004 Restated for Reorganization

(UNAUDITED)

Millions of Dollars - Three Months Ended March 31	**2005**	**2004**
Revenues		
Sales and operating revenue	$ 45,443	$ 38,745
Excise taxes	1,887	1,759
Equity in income of affiliates	159	152
	47,489	40,656
Costs and Expenses		
Purchases	35,184	31,120
Operating expenses	2,416	2,211
Oil and gas exploration expenses including amortization of unproved properties	88	79
Taxes other than income taxes	2,144	1,970
Depreciation, depletion and amortization, and retirements and abandonments	1,356	1,444
Selling, general and administrative expenses	1,030	951
	42,218	37,775
Income Before Interest and Income Taxes	5,271	2,881
Interest expense	329	271
Interest income	576	303
Income Before Income Taxes	5,518	2,913
Income tax provision	1,460	798
Dividends on preferred stock of subsidiary	223	223
Minority interest	732	139
Net Income	$ 3,103	$ 1,753

BP CORPORATION NORTH AMERICA INC.

CONSOLIDATED BALANCE SHEET

2004 Restated for Reorganization

(UNAUDITED)

Millions of Dollars	**March 31 2005**	**Dec 31 2004**
ASSETS		
Current Assets		
Cash and cash equivalents	$ 422	$ 294
Marketable securities	142	158
Accounts and notes receivable, less allowances of $112 and $112	12,654	13,159
Receivables - affiliates	1,396	881
Inventories	2,539	2,961
Prepaid expenses and other	3,834	2,692
	20,987	20,145
Property, Plant and Equipment - at cost		
Exploration and production	62,478	62,015
Refining and marketing	24,457	24,339
Gas, power and renewables	2,971	2,985
Corporate and other	5,986	6,160
	95,892	95,499
Less accumulated depreciation, depletion and amortization	44,413	43,785
	51,479	51,714
Other Non-Current Assets		
Investments in affiliates	8,993	8,932
Notes and amounts due from affiliates	65,140	96,903
Investments, long-term receivables and other	3,899	3,162
Goodwill	6,735	6,735
	84,767	115,732
	$ 157,233	$ 187,591

BP CORPORATION NORTH AMERICA INC.

CONSOLIDATED BALANCE SHEET

2004 Restated for Reorganization

(UNAUDITED)

Millions of Dollars	March 31 2005	Dec 31 2004
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Current portion of long-term debt and capital lease obligations	$ 672	$ 1,180
Current portion of long-term debt - affiliates	2,350	2,350
Short-term obligations	3,019	3,101
Accounts payable - trade	12,098	12,683
Accounts payable - affiliates	2,270	2,277
Taxes payable, including income taxes	2,340	2,302
Accrued liabilities	4,275	4,101
	27,024	27,994
Long-Term Obligations		
Amounts due to affiliates	39,509	72,454
Long-term debt	3,783	3,800
Long-term debt - affiliates	2,112	2,322
Capital lease obligations	135	142
	45,539	78,718
Other Non-Current Liabilities		
Deferred income taxes	11,971	11,916
Accruals and reserves	6,674	6,267
	18,645	18,183
Minority Interest		
Preferred stock of subsidiary	13,836	13,836
Other minority interest	4,775	4,479
	18,611	18,315
Shareholder's Equity		
Common stock - 1,000 shares issued and outstanding	1	1
Additional paid-in capital	12,996	12,996
Retained earnings	35,334	32,231
Accumulated other comprehensive income (loss):		
Foreign currency translation adjustments	(779)	(690)
Unrealized gains on hedging activities	7	-
Unrealized gains on marketable securities	12	-
Minimum pension liability adjustments	(157)	(157)
	47,414	44,381
	$ 157,233	$ 187,591

BP CORPORATION NORTH AMERICA INC.

CONSOLIDATED STATEMENT OF SHAREHOLDER'S EQUITY

(UNAUDITED)

Millions of Dollars	Common Stock	Additional Paid-In Capital	Retained Earnings	Other Comprehensive Income (Loss)	Total
January 1, 2004	$ 1	$ 12,996	$ 26,714	$ (1,078)	$ 38,633
Net income	-	-	5,552	-	5,552
Foreign currency translation adjustments	-	-	-	214	214
Minimum pension liability adjustments, net of $12 tax	-	-	-	17	17
Comprehensive income					5,783
Cash dividends paid	-	-	(35)	-	(35)
December 31, 2004	1	12,996	32,231	(847)	44,381
Net income	-	-	3,103	-	3,103
Foreign currency translation adjustments	-	-	-	(89)	(89)
Unrealized gains on hedging activities, net of $4 tax	-	-	-	7	7
Unrealized gains on marketable securities, net of $6 tax	-	-	-	12	12
Comprehensive income					3,033
March 31, 2005	$ 1	$ 12,996	$ 35,334	$ (917)	$ 47,414

BP CORPORATION NORTH AMERICA INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

2004 Restated for Reorganization

(UNAUDITED)

Millions of Dollars – Three Months Ended March 31	**2005**	**2004**
Operating Activities		
Net income	$ 3,103	$ 1,753
Adjustments to reconcile net income to net cash provided by operations:		
Depreciation, depletion and amortization and retirements and abandonments	1,356	1,444
Amortization on unproved oil and gas properties	84	21
Deferred income taxes	122	(199)
(Gain) loss on sales of assets	(1,111)	13
Dividends paid on preferred stock of subsidiary	223	223
Minority interest	732	139
Changes in operating assets and liabilities, net of acquisitions and divestments:		
Decrease in marketable securities	16	15
Decrease (increase) in accounts and notes receivable	505	(801)
Increase in receivables – affiliates	(515)	(379)
Increase in inventories and prepaid expenses	(773)	(47)
Decrease in accounts payable and accrued liabilities	(375)	(151)
(Decrease) increase in accounts payable – affiliates	(7)	1,135
Increase in taxes payable	38	42
Other – net	(235)	(19)
Net cash provided by operating activities	3,163	3,189
Investing Activities		
Capital expenditures	(1,540)	(1,262)
Proceeds from the sale of property and other assets	1,231	267
Investments in affiliates, net	(61)	(154)
Other	(436)	(500)
Net cash used in investing activities	(806)	(1,649)
Financing Activities		
Net changes in long-term debt and capital lease obligations	(532)	194
Net changes in long-term debt - affiliates	(210)	141
Net changes in notes and amounts due to and from affiliates	(1,182)	(1,849)
Net changes in short-term obligations	(82)	(19)
Dividends paid on preferred stock of subsidiary	(223)	(223)
Net cash used in financing activities	(2,229)	(1,756)
Increase (decrease) in Cash and Cash Equivalents	128	(216)
Cash and cash equivalents, Beginning of Year	294	633
Cash and cash equivalents, End of Period	$ 422	$ 417

REPORT OF ERNST & YOUNG LLP, INDEPENDENT AUDITORS

Board of Directors and Shareholder
BP Corporation North America Inc.

We have audited the accompanying consolidated balance sheet of BP Corporation North America Inc. (a wholly owned subsidiary of BP America Inc.) and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, shareholder's equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of BP Corporation North America Inc. and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" and Emerging Issues Task Force Issue No. 02-03, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities."

During 2004 and 2003, as more fully explained in the Basis of Presentation note to the consolidated financial statements, BP p.l.c. changed the operations that comprise BP Corporation North America Inc., the reporting entity.

Chicago, Illinois
February 7, 2005

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF INCOME

2003 Restated for Reorganization

Millions of Dollars - Year Ended December 31	2004	2003
Revenues		
Sales and operating revenue	$ 161,415	$ 131,154
Excise taxes	7,314	7,176
Equity in income of affiliates	550	488
	169,279	138,818
Costs and Expenses		
Purchases	129,340	102,169
Operating expenses	9,437	8,267
Oil and gas exploration expenses including amortization of unproved properties	430	353
Taxes other than income taxes	8,140	7,878
Depreciation, depletion and amortization, and retirements and abandonments	6,251	6,636
Selling, general and administrative expenses	4,824	4,338
	158,422	129,641
Income Before Interest and Income Taxes	10,857	9,177
Interest expense	1,486	1,029
Interest income	1,796	1,113
Income Before Income Taxes	11,167	9,261
Income tax provision	3,997	2,507
Dividends on preferred stock of subsidiary	892	839
Minority interest	726	250
Income Before Cumulative Effect of Accounting Changes	5,552	5,665
Cumulative effect of accounting changes, net of tax	-	(1)
Net Income	$ 5,552	$ 5,664

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

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

2003 Restated for Reorganization

Millions of Dollars - December 31	2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	$ 294	$ 633
Marketable securities	158	100
Accounts and notes receivable, less allowances of $112 and $88	13,619	9,341
Receivables - affiliates	881	1,337
Inventories	2,961	2,651
Prepaid expenses and other	2,232	2,176
	20,145	16,238
Property, Plant and Equipment - at cost		
Exploration and production	62,015	59,656
Refining and marketing	19,143	19,103
Petrochemicals	10,658	11,021
Gas, power and renewables	2,985	2,712
Corporate and other	698	1,105
	95,499	93,597
Less accumulated depreciation, depletion and amortization	43,785	42,245
	51,714	51,352
Other Non-Current Assets		
Investments in affiliates	8,932	7,461
Notes and amounts due from affiliates	96,903	78,577
Investments, long-term receivables and other	3,162	3,080
Goodwill	6,735	6,735
	115,732	95,853
	$ 187,591	$ 163,443

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

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

2003 Restated for Reorganization

Millions of Dollars - December 31	2004	2003
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Current portion of long-term debt and capital lease obligations	$ 1,180	$ 247
Current portion of long-term debt - affiliates	2,350	461
Short-term obligations	3,101	3,050
Accounts payable - trade	14,470	10,398
Accounts payable - affiliates	2,277	1,743
Taxes payable, including income taxes	2,302	2,649
Accrued liabilities	2,314	2,013
	27,994	20,561
Long-Term Obligations		
Amounts due to affiliates	72,454	61,031
Long-term debt	3,800	4,942
Long-term debt - affiliates	2,322	2,058
Capital lease obligations	142	149
	78,718	68,180
Other Non-Current Liabilities		
Deferred income taxes	11,916	11,931
Accruals and reserves	6,267	6,484
	18,183	18,415
Minority Interest		
Preferred stock of subsidiary	13,836	13,836
Other minority interest	4,479	3,818
	18,315	17,654
Shareholder's Equity		
Common stock - 1,000 shares issued and outstanding	1	1
Additional paid-in capital	12,996	12,996
Retained earnings	32,231	26,714
Accumulated other comprehensive loss:		
Foreign currency translation adjustment	(690)	(904)
Pension liability adjustment	(157)	(174)
	44,381	38,633
	$ 187,591	$ 163,443

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

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF SHAREHOLDER'S EQUITY

2003 Restated for Reorganization

Millions of Dollars	Common Stock	Additional Paid-In Capital	Retained Earnings	Other Compre-hensive Income (Loss)	Total
January 1, 2003	$ 1	$ 12,996	$ 21,050	$ (1,666)	$ 32,381
Net income	-	-	5,664	-	5,664
Foreign currency translation adjustment	-	-	-	(33)	(33)
Pension liability adjustment net of $389 tax	-	-	-	723	723
Reclassification for gains included in net income	-	-	-	(102)	(102)
Comprehensive income					6,252
December 31, 2003	1	12,996	26,714	(1,078)	38,633
Net income	-	-	5,552	-	5,552
Foreign currency translation adjustment	-	-	-	214	214
Pension liability adjustment net of $12 tax	-	-	-	17	17
Comprehensive income					5,783
Cash dividends paid	-	-	(35)		(35)
December 31, 2004	$ 1	$ 12,996	$ 32,231	$ (847)	$ 44,381

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

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

2003 Restated for Reorganization

Millions of Dollars – Year Ended December 31	2004	2003
Operating Activities		
Net income	$ 5,552	$ 5,664
Adjustments to reconcile net income to net cash provided by operations:		
Depreciation, depletion and amortization and retirements and abandonments	6,251	6,636
Amortization on unproved oil and gas properties	144	153
Deferred income taxes	(128)	(531)
Loss (gain) on sales of assets	19	(516)
Dividends paid on preferred stock of subsidiary	892	839
Minority interest	726	250
Changes in operating assets and liabilities, net of acquisitions and divestments:		
(Increase) decrease in marketable securities	(58)	9
Increase in accounts and notes receivable	(4,380)	(1,511)
Decrease in receivables - affiliates	451	620
Increase in inventories and prepaid expenses	(433)	(488)
Increase in accounts payable and accrued liabilities	4,434	123
Increase (decrease) in accounts payable - affiliates	544	(260)
(Decrease) increase in taxes payable	(347)	780
Other - net	(96)	(1,094)
Net cash provided by operating activities	13,571	10,674
Investing Activities		
Capital expenditures	(6,691)	(7,071)
Acquisition of BP Solvay joint venture	(379)	-
Proceeds from the sale of property and other assets	1,733	4,177
Investments in affiliates, net	(1,818)	109
Other	(913)	237
Net cash used in investing activities	(8,068)	(2,548)
Financing Activities		
Net changes in long-term debt and capital lease obligations	(216)	(1,192)
Net changes in long-term debt - affiliates	2,153	232
Net changes in notes and amounts due to and from affiliates	(6,903)	(7,141)
Net changes in short-term obligations	51	615
Dividends paid on preferred stock of subsidiary	(892)	(839)
Dividends paid on common stock	(35)	-
Net cash used in financing activities	(5,842)	(8,325)
Decrease in Cash and Cash Equivalents	(339)	(199)
Cash and cash equivalents, Beginning of Year	633	832
Cash and cash equivalents, End of Year	$ 294	$ 633

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2003 Restated for Reorganization

Basis of Presentation

BP Corporation North America Inc. (the Company) is a wholly owned subsidiary of BP America Inc. (BP America). BP America is a wholly owned subsidiary of BP p.l.c. (BP). BP and its subsidiaries are hereafter referred to as the BP group.

On December 31, 2003, BP America and its subsidiaries transferred ownership of BP Chemicals Inc. to a subsidiary of the Company in exchange for 836,000 shares of preferred stock of BP Company North America Inc., a wholly owned subsidiary of the Company.

On December 15, 2004, BP America transferred ownership of North America Funding Company to the Company via a capital contribution.

The ownership of preferred stock issued by subsidiaries of the Company and held by subsidiaries of BP America is accounted for as minority interest in the accompanying financial statements.

The transfers of ownership interests, assets and liabilities to subsidiaries of the Company by BP America and its subsidiaries represent reorganizations of entities under common control (a change in reporting entity) and have been accounted for at their historical cost bases. Assets and liabilities were transferred to the Company or its subsidiaries at its parent's or its subsidiaries' basis, with no adjustment to fair value. Prior year amounts in these financial statements have been restated for comparability.

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2003 Restated for Reorganization

The impact of the 2004 change in reporting entity and certain other reclassifications are shown in the following table.

Millions of Dollars – As of or for the Year Ended December 31, 2003	As Previously Stated	Effect of Changes	Restated
Consolidated Statement of Income			
Revenues	$ 138,818	$ -	$ 138,818
Costs and expenses	(129,816)	175	(129,641)
Interest, net	(196)	280	84
Income tax provision	(2,404)	(103)	(2,507)
Dividends on preferred stock of subsidiary	(839)	-	(839)
Minority interest	(250)	-	(250)
Cumulative effect of accounting changes, net of tax	(1)	-	(1)
Net Income	$ 5,312	$ 352	$ 5,664
Consolidated Balance Sheet			
Current assets	$ 14,398	$ 1,840	$ 16,238
Property, plant and equipment, net	51,352	-	51,352
Other non-current assets	72,395	23,458	95,853
Total Assets	$ 138,145	$ 25,298	$ 163,443
Current liabilities	$ 18,939	$ 1,622	$ 20,561
Non-current liabilities	63,575	23,020	86,595
Minority interest	17,654	-	17,654
Shareholder's equity	37,977	656	38,633
Total Liabilities and Shareholder's Equity	$ 138,145	$ 25,298	$ 163,443
Consolidated Statement of Cash Flows			
Net cash provided by (used in):			
Operating activities	$ 10,353	$ 321	$ 10,674
Investing activities	(2,548)	-	(2,548)
Financing activities	(7,986)	(339)	(8,325)
Decrease in cash and cash equivalents	(181)	(18)	(199)
Cash and cash equivalents, beginning of year	825	7	832
Cash and Cash Equivalents, End of Year	$ 644	$ (11)	$ 633

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2003 Restated for Reorganization

Note 1 Summary of Significant Accounting Policies

Consolidation Policy. The assets, liabilities and results of operations of subsidiaries in which the Company has a controlling interest are included in the Consolidated Financial Statements. The Company also consolidates its proportionate share of undivided interests in certain pipelines and oil and gas joint ventures. Investments in companies in which less than a controlling interest is held are generally accounted for by the equity method. All significant intercompany transactions and accounts are eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires estimates and assumptions that affect certain reported amounts and related disclosures. Actual results could differ from estimates and assumptions made.

Inventories. Inventories are carried at the lower of current market value or cost. Cost is determined under the last-in, first-out (LIFO) method for the majority of inventories of crude oil, petroleum products and chemical products. The costs of remaining inventories are determined on the first-in, first-out (FIFO) or average cost methods.

Oil and Gas Exploration and Development. The Company follows the successful efforts method of accounting. Costs of property acquisitions, successful exploratory wells, all development costs (including CO_2 and certain other injected materials that benefit production over multiple years in enhanced recovery projects) and support equipment and facilities are capitalized. Unsuccessful exploratory wells are expensed when determined to be non-productive. Production costs, overhead and all exploration costs other than exploratory drilling, including geological and geophysical costs, are charged against income as incurred.

Exploration license acquisition costs are initially capitalized as an intangible fixed asset and are amortized over the estimated period of exploration. Where proved reserves of oil or natural gas are determined and development is sanctioned, the unamortized cost is transferred to tangible production assets. Where exploration is unsuccessful, the unamortized cost is expensed. Property, plant and equipment includes capitalized exploration license acquisition costs of $278 million and $294 million at December 31, 2004 and 2003, respectively.

Property acquisition costs for individually significant unproved properties are assessed at least annually for impairment. The acquisition costs of all other unproved properties are aggregated, and the portion estimated to be nonproductive based upon past experience is amortized over the projected holding periods.

Property, Plant and Equipment.
Depreciation, depletion and amortization. Depletion of the cost of producing oil and gas properties, amortization of related intangible drilling and development costs and depreciation of tangible leases and well equipment are recognized using the unit-of-production method. Depreciation of other plant and equipment is computed on a straight-line basis over the estimated economic lives of the facilities, which for refining and chemical

facilities average 20 years, for administrative buildings average 45 years and for service stations average 15 years.

Dismantlement, Restoration and Abandonment Costs. On January 1, 2003, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143 "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires that a liability be recorded equal to the fair value of the asset retirement obligation when incurred, typically when the asset is installed at the production location. When the liability is initially recorded, an equivalent amount is capitalized as part of the cost of the asset. Over time, the liability is accreted for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset.

The cumulative effect of adopting SFAS 143, as of January 1, 2003, was a pre-tax charge to income of approximately $99 million (see Note 12). Prior to the adoption of SFAS 143, the estimated costs to dismantle, restore and abandon oil and gas properties were accrued over the properties' productive lives on the unit-of-production method.

Impairment. Carrying amounts of long-lived assets, other than unproved properties, are reviewed when events or circumstances indicate that such carrying amounts may not be recoverable. Assets that are to be held and used with recorded values that are not expected to be recovered through future cash flows are written down to current fair value. Fair value is generally determined from estimated discounted future net cash flows. Assets that are held for sale are reported at the lower of carrying amount or fair value less cost to sell. Impairment charges are included in depreciation, depletion and amortization.

Dispositions. Gains or losses from retirements or dispositions of property, plant and equipment are credited or charged to income, except for normal sales of oil and gas producing properties, which are charged or credited to accumulated depreciation until the entire field is depleted or disposed.

Goodwill. Goodwill is not amortized, but instead is assessed annually for impairment. Other intangibles are amortized over their useful life.

Derivatives. The Company uses derivative financial instruments (derivatives) to manage certain exposures to fluctuations in foreign currency exchange rates and interest rates, and to manage some of its margin exposure from changes in oil and natural gas prices. Derivatives are also traded in conjunction with these risk management activities. The Company currently does not designate any derivatives as hedges, and as a result, changes in the fair value of all derivatives held are recognized in earnings each period.

Foreign Currencies. Assets and liabilities of non-US subsidiaries using the local currency as their functional currency are translated at exchange rates in effect at the balance sheet date. Income and expenses are translated at average exchange rates for the period presented. The effects of these translation adjustments are reported in other comprehensive income. Exchange gains and losses arising from transactions denominated in a currency other than the functional currency of the entity involved are recognized in income.

Environmental Liabilities. The Company has provided in its accounts for the reasonably estimable future costs of probable environmental remediation obligations relating to current and past activities, including obligations for previously disposed assets or businesses. In the case of long-lived cleanup projects, the effects of factors such as improved application of known technologies and methodologies are considered in determining the amount of estimated liabilities. The liability is undiscounted and primarily consists of costs such as site assessment, monitoring, equipment, utilities and the treatment and disposal of soil and ground water.

Revenue Recognition. *Revenues associated with the sale of oil, natural gas liquids,* liquefied natural gas, petroleum and chemical products and all other items are recognized when title passes to the customer. Revenues from the production of natural gas and oil from properties in which the Company has an interest with other producers are recognized either on the basis of the Company's working interest in those properties (the entitlement method) or on the basis of the Company's share of production sold (the sales method). The difference between the entitlement and sales methods is not significant.

Gains or losses resulting from divestments of assets or businesses are included in sales and operating revenue.

Stock Options. Employees of the Company participate in certain employee share option plans of BP. Options granted by BP have an exercise price equal to the market price on the date of grant. Options are generally exercisable one to three years after the date of grant, and lapse after ten years. BP and the Company use the intrinsic value method of *accounting for stock options awarded to employees. The following table illustrates the* effect on net income if compensation expense were instead determined based upon the fair value of the stock options at grant date to the extent the options related to employees of the Company and the expense was allocated to the Company.

Millions of Dollars - Year Ended December 31	2004	2003
Net income - as reported	$ 5,552	$ 5,664
Deduct - stock-based employee compensation expense based on fair value recognition provisions, net of related tax effects	(41)	(44)
Pro forma net income	$ 5,511	$ 5,620

The fair value of stock options was estimated using a Black-Scholes option pricing model with the following assumptions:

	2004	2003
Risk-free interest rate	4.0%	3.5%
Expected volatility	22%	30%
Expected life	5 years	1-5 years
Expected dividend yield	3.75%	4.0%
Weighted average fair value of options granted	$1.35	$1.44

Shipping and Handling Costs. Shipping and handling costs are included in costs and expenses.

Maintenance and Repair Costs. Costs of major maintenance, refits or repairs are capitalized when it enhances the performance of an asset above its originally assessed standard of performance, replaces an asset or part of an asset which was separately depreciated and which is then written off, or restores the economic benefits of an asset which has been fully depreciated. All other maintenance and repairs costs are charged to costs and expenses as incurred.

Adoption of New Accounting Standards. In October 2002, the Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) reached a consensus (EITF Issue No. 02-03) which rescinded EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). As a result, all energy-related, non-derivative contracts (such as transportation, storage, tolling, and requirements contracts that do not meet the definition of a derivative) that were previously accounted for at fair value pursuant to EITF 98-10 are now accounted for as executory contracts on the accrual basis. The cumulative effect of adopting the consensus at January 1, 2003, resulted in a pre-tax credit to income of $97 million.

On January 1, 2003, the Company adopted FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 expands the disclosure requirements for guarantees and requires the guarantor to recognize a liability for the fair value of the obligation assumed under a guarantee. The initial recognition and measurement requirements of FIN 45 are applied prospectively to guarantees issued or modified after December 31, 2002. The adoption of FIN 45 did not have a material effect on the Company's financial position or results of operations.

On January 1, 2003, the Company adopted SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS 146) which addresses accounting for restructuring and similar costs. SFAS 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3. SFAS 146 requires that a liability for costs associated with an exit or disposal activity be recognized when the liability is incurred, rather than at the date of an entity's commitment to an exit plan. SFAS 146 requires that the liability be initially measured and recorded at fair value. The adoption of SFAS 146 did not have a material effect on the Company's financial position or results of operations.

On June 1, 2003, the Company adopted SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" (SFAS 150). SFAS 150 establishes standards for classifying and measuring certain financial instruments that have characteristics of both liabilities and equity. SFAS 150 applies to instruments entered into or modified after May 31, 2003. For instruments existing at May 31, 2003, SFAS 150 is effective for accounting periods beginning after June 15, 2003. The adoption of SFAS 150 had no effect on the Company's financial position or results of operations.

On July 1, 2003, the Company adopted SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149). SFAS 149 amends and clarifies the financial accounting and reporting of derivative instruments and hedging activities under SFAS 133. SFAS 149 applies to contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 did not have a material effect on the Company's financial position or results of operations.

During 2003, the FASB issued and then revised Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 clarifies the application of existing consolidation requirements to entities where a controlling financial interest is achieved through arrangements that do not involve voting interests. Under FIN 46, a variable interest entity is consolidated if a company is subject to a majority of the risk of loss from the variable interest entity's activities or entitled to receive a majority of the entity's residual returns. The adoption of FIN 46 did not have a material effect on the Company's financial position or results of operations.

In May 2004, the FASB issued Staff Position No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the Medicare Act). The provisions of the Medicare Act provide for a federal subsidy for plans that provide prescription drug benefits to Medicare-eligible retired employees and meet certain qualifications. Alternatively, the Medicare Act allows prescription drug plan sponsors to co-ordinate with the Medicare benefit. As a result of the Medicare Act, the benefit obligation of the Company's postretirement benefit plans was reduced by $577 million at December 31, 2004. See Note 18, Pension and Other Postretirement Benefits for additional information.

In November 2004, the EITF reached a consensus on Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations" (EITF 03-13). Under EITF 03-13, a disposed component of an enterprise is classified as a discontinued operation only where the ongoing entity has no continuing direct cash flows and does not retain an interest, contract or other arrangement sufficient to enable the entity to exert significant influence over the disposed component's operating and financial policies after disposal. EITF 03-13 is effective for a component of an enterprise that is either disposed of or classified as held for sale in accounting periods beginning after December 15, 2004. EITF 03-13 had no effect on the Company's financial position or results of operations.

In December 2004, the FASB issued Staff Position No. 109-1, "Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004" (FSP 109-1). FSP 109-1, effective upon issuance, requires that the manufacturers' deduction provided for under the American Jobs Creation Act of 2004 (the Jobs Creation Act) be accounted for as a special deduction in accordance with SFAS 109, "Accounting for Income Taxes", rather than a tax rate reduction. The manufacturers' deduction will be recognized by the Company in the year the benefit is earned.

In December 2004, the FASB issued Staff Position No. 109-2, "Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004" (FSP 109-2). The Jobs Creation Act provides a special one-time provision allowing earnings of certain foreign companies to be repatriated at a reduced tax rate. FSP 109-2, effective upon issuance, permits additional time beyond the financial reporting period of enactment in order to evaluate the effect of the Jobs Creation Act without undermining an entity's assertion that repatriation of foreign earnings is not expected within the foreseeable future. As provided by FSP 109-2, the Company has elected to defer a decision on potentially altering current plans regarding the permanent reinvestment in certain foreign subsidiaries and foreign corporate joint ventures. The income tax effects associated with any repatriation of unremitted earnings as a result of the Jobs Creation Act cannot be reasonably estimated at this time.

Recently Issued Accounting Pronouncements and Guidance. In November 2004, the FASB issued SFAS No. 151, "Inventory Costs- an amendment of ARB No. 43, Chapter 4" (SFAS 151). SFAS 151 requires that items, such as idle facility expense, excessive spoilage, double freight and re-handling costs, be recognized as current-period charges. SFAS 151 also requires that the allocation of fixed production overheads to the costs of conversion be based on the normal capacity of the production facilities. SFAS 151 is effective for fiscal years beginning after June 15, 2005. SFAS 151 is not expected to have a material effect on the Company's financial position or results of operations. The Company plans to adopt SFAS 151 on January 1, 2005.

In December 2004, the FASB issued SFAS No. 153, "Exchange of Nonmonetary Assets- an amendment of APB Opinion No. 29" (SFAS 153). SFAS 153 eliminates the Accounting Principles Board Opinion No. 29 exception for nonmonetary exchanges of similar productive assets and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS 153 is effective for nonmonetary asset exchanges occurring after June 30, 2005. SFAS 153 is not expected to have a material effect on the Company's financial position or results of operations. The Company plans to adopt SFAS 153 on January 1, 2005.

Emerging Accounting and Reporting Issues. In November 2004, the EITF began discussion of Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" (EITF 04-13). EITF 04-13 addresses accounting issues that arise when a company both sells inventory to and buys inventory from another entity in the same line of business. The purchase and sale transactions may be pursuant to a single contractual arrangement or separate contractual arrangements, and the inventory purchased or sold may be in the form of raw material, work-in-process or finished goods. At issue is whether the revenue, cost of inventory and cost of sales should be recorded at fair value or whether the transactions should be classified as nonmonetary transactions. The EITF, which did not reach a consensus on the issue, requested the FASB staff to further explore the alternative views. Should the EITF reach a consensus on EITF 04-13 requiring these transactions to be recorded as exchanges measured at book value, the net presentation would reduce the Company's revenues and purchases by equal amounts with no impact on net income. The Company has not determined the amount of the reduction in revenues and purchases under such an interpretation.

SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" (SFAS 19) requires the cost of drilling an exploratory well to be capitalized pending determination of whether the well has found proved reserves. If this determination cannot be made at the conclusion of drilling, SFAS 19 sets out additional requirements for continuing to carry the cost of the well as an asset. These requirements include firm plans for further drilling and a one-year time limitation on continued capitalization in certain instances. Subsequent to the issuance of SFAS 19, as a result of the increasing complexity of oil and gas projects due to drilling in remote and deepwater offshore locations, entities increasingly require more than one year to complete all of the activities that permit recognition of proved reserves. In addition, because of new technologies, in certain situations additional exploratory wells may no longer be required before a project can commence.

In February 2005, the FASB issued a proposed Staff Position "Accounting for Suspended Well Costs" (FSP 19-a). FSP 19-a, if adopted, would amend SFAS 19 to permit the continued capitalization of exploratory well costs beyond one year if (a) the well found a sufficient quantity of reserves to justify its completion as a producing well and (b) the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, or if an entity obtains information that raises substantial doubt about the economic or operational viability of the project, the exploratory well is assumed to be impaired, and its costs, net of any salvage value, would be charged to expense. FSP 19-a provides a number of indicators that would be considered in order to demonstrate that sufficient progress was being made in assessing the reserves and the economic viability of the project.

Reclassifications. Certain reclassifications have been made to prior year balances in order to conform to current year presentation.

Note 2 Restructuring and Special Items

In April 2004, BP announced its intention to consolidate its olefins and derivatives business (the O&D Business) of its Petrochemicals segment into a stand-alone entity able to operate separately from the BP group. BP intends to divest the O&D Business, possibly starting with an initial public offering in the second half of 2005, depending on market conditions and the receipt of necessary approvals.

Effective January 1, 2005, the O&D Business will be included within the Corporate and Other segment, and the remaining activities of the Petrochemicals segment, comprising the aromatics and acetyls business, will be included within the Refining and Marketing segment.

The Petrochemicals results of operations for 2004 included charges of $483 million for asset impairments related to the anticipated closure or divestiture of three chemical plants located in the US. Exploration and Production results of operations for 2004 included charges of $341 million for asset impairments related to a gas processing plant in the US, a field in the Gulf of Mexico and interests in two production sharing contracts in Indonesia.

Exploration and Production results of operations in 2003 included asset impairments of $830 million. This charge included $296 million for four fields in the Gulf of Mexico, $108 million for a field in Indonesia, $105 million for a field in China, and $217 million for two fields in Venezuela.

Note 3 Acquisitions and Disposals

In 2004, BP reached an agreement with Solvay S.A. (Solvay) to acquire Solvay's 51% share of the BP Solvay Polyethylene North America joint venture for $379 million. The acquisition, which resulted in the joint venture becoming a wholly owned subsidiary of the Company, did not have a material effect on the Company's results of operations.

In 2004, the Company divested its Fabrics and Fibers business and certain other US Petrochemical assets. These divestments in total were not material to the Company's results of operations, as the sales proceeds approximated the carrying value of the assets.

In 2003, Repsol exercised its option to acquire an additional 20 percent interest in BP Trinidad and Tobago LLC (BP Trinidad). As a result, the Company recognized a gain of $660 million, and the Company's interest in BP Trinidad is now 70 percent.

In 2003, the Company divested interests in a number of exploration and production properties. A package of Gulf of Mexico assets were sold to Apache Corporation. Interests in 14 UK Southern North Sea gas fields, together with associated pipelines and onshore processing facilities, were sold to Perenco for $120 million. These sales did not have a significant impact on 2003 earnings, as the assets sold to Apache were written down in 2002, and the net book value of the assets sold to Perenco approximated the sales proceeds. The Company also disposed of its remaining interest in a Chicago office building that was initially retained in a 1998 sale and leaseback transaction, and recognized a gain of $120 million.

Note 4 Cash Flow Information

The Consolidated Statement of Cash Flows provides information about changes in cash and cash equivalents. The Company considers all investments with original maturities of three months or less to be cash equivalents. The effect of foreign currency exchange rate fluctuations on total cash and cash equivalent balances was not significant.

Net cash provided by operating activities reflects cash payments for interest and income taxes as follows.

Millions of Dollars - Year Ended December 31	2004	2003
Interest paid	$ 657	$ 812
Income taxes paid, net of refunds	2,026	1,652

BP America pays US income taxes on behalf of the Company.

Note 5 Financial Instruments

Fair Value

The carrying amount and fair value of the Company's financial instruments at December 31, 2004 and 2003, are shown in the table below. Bracketed amounts in the carrying amount column represent liabilities or accruals recognized for potential cash outflows. Bracketed amounts in the fair value column represent estimated cash outflows required to settle the financial instrument at current market rates.

	2004		2003	
Millions of Dollars - December 31	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Assets				
Cash and cash equivalents	$ 294	$ 294	$ 633	$ 633
Marketable securities	158	158	100	100
Liabilities				
Short-term obligations	(3,101)	(3,101)	(3,050)	(3,050)
Long-term debt (including current maturities)	(4,954)	(5,315)	(5,147)	(5,607)
Swap agreements				
Interest rate	2	2	-	-
Trading activities				
Natural gas price contracts	543	543	330	330
Power price contracts	148	148	120	120
Oil price contracts	(13)	(13)	11	11

The carrying amount of assets and liabilities in the above table are included in the Consolidated Balance Sheet under the indicated captions. The carrying amount of derivative financial instruments is included in other current assets, accounts payable - trade, other non-current assets or accruals and reserves, as appropriate in the Consolidated Balance Sheet.

Amounts due from, or payable to affiliates are not included in the table. Such amounts are reported in the Consolidated Balance Sheet at carrying amounts, which generally approximate fair value.

The following methods and assumptions were used by the Company in estimating the fair values of financial instruments.

Cash and cash equivalents. The carrying amount reported in the Consolidated Balance Sheet for cash and cash equivalents approximates fair value.

Marketable securities. Substantially all marketable securities are classified as available-for-sale and reported at fair value, with unrealized holding gains and losses, net of tax, reported in accumulated other comprehensive income.

Short-term obligations and long-term debt. The fair value of the Company's non-affiliate debt instruments was estimated using quoted prices, or where such prices were not available, discounted cash flow analyses, based on the Company's current incremental borrowing rates for similar types of borrowing arrangements and maturities.

Derivative financial instruments. The fair value of derivative financial instruments was based on quoted market prices, current settlement values or quoted market prices of comparable instruments.

Derivative Financial Instruments

The Company enters into futures contracts, swap agreements, forwards and option contracts to manage certain exposures to price fluctuations on hydrocarbon transactions. These contracts are used to convert specific sales and purchase contracts from fixed to market prices and to manage exposure to price differences between locations.

As part of its energy trading activities, the Company maintains active trading positions in a variety of oil, natural gas, and power price contracts. These derivatives are principally comprised of futures contracts, swap agreements, forwards and option contracts.

Credit and Market Risk

Financial instruments involve, to varying degrees, credit and market risk. With regard to credit risk, the Company would be exposed to loss in the event of nonperformance by a counterparty. A significant portion of the Company's receivables is due from other oil and gas and chemical companies. Collection of these receivables could be influenced by economic factors affecting these industries and the countries in which the Company and its customers operate. The Company controls credit risk through credit approvals, limits, use of netting arrangements and monitoring procedures. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment. A majority of the derivative financial instruments are either exchange traded or with major financial institutions. The Company does not anticipate nonperformance by any significant counterparties. The fair value of financial instruments with a positive fair value represents the Company's exposure to credit risk.

Market risk is the possibility that a change in interest rates, currency exchange rates or the price of oil, natural gas, or power will cause the value of a financial instrument to decrease, or the obligations to become more costly to settle. When derivatives are used for the purpose of risk management, they do not expose the Company to incremental market risk as gains and losses on the derivatives offset losses and gains on the underlying asset, liability or transaction. When derivatives are entered into for trading purposes, the exposure of the Company to market risk is limited to changes in their fair values.

Commitments and Guarantees

At December 31, 2004, the Company's contractual commitments under throughput and take or pay agreements amounted to $1,642 million. In addition, the Company has guaranteed the performance of certain subsidiaries of the BP group that are not subsidiaries of the Company. The most significant relate to guarantees to counterparties of physical trading contracts entered into by an affiliate amounting to $988 million. The Company also guarantees the loans of certain equity accounted affiliates totaling $380 million at December 31, 2004. Guarantees of outstanding loans of third parties amounted to $49 million at December 31, 2004.

In order to provide liquidity for the Company's employee savings plans, in 2004 the Company agreed to advance the savings plans up to $200 million. Amounts borrowed by the savings plans under a revolving loan facility do not bear interest and are repayable within three days. At December 31, 2004, there were no amounts outstanding under the agreement.

Note 6 Inventories

Millions of Dollars - December 31	2004	2003
Crude oil, natural gas and other petroleum products	$ 1,946	$ 1,638
Chemical products	356	321
Materials, supplies and other	659	692
	$ 2,961	$ 2,651

As a result of the use of the LIFO inventory valuation method, some inventories are reported in the balance sheet at amounts less than current cost. Inventories carried under the LIFO method represented approximately 60 percent of total year-end inventory carrying values in 2004, and 57 percent in 2003. It is estimated that inventories would have been approximately $3,486 million and $2,237 million higher than reported at December 31, 2004 and 2003, respectively, if the quantities valued on the LIFO basis were instead valued at current prices.

Note 7 Investments in Affiliates

The Company conducts portions of its business through investments in companies accounted for using the equity method. The equity affiliates are primarily engaged in exploration and production in South America, transportation of crude oil and petroleum products in the United States and petroleum and chemical operations in Asia. The following table summarizes financial information for the Company's equity affiliates combined, as well as the Company's proportionate interest in the affiliates.

	Investee	
Millions of Dollars – December 31	**2004**	**2003**
Current assets	$ 3,769	$ 3,337
Other assets	11,359	10,528
Current liabilities	2,596	2,505
Other liabilities	4,045	3,242
Net assets	$ 8,487	$ 8,118
Total revenues	$ 7,329	$ 5,699
Income before income taxes	2,242	1,371
Net income	1,296	1,156

	Company Share	
Millions of Dollars – December 31	**2004**	**2003**
Carrying value of equity investments	$ 4,516	$ 4,304
Other investments and loans	4,416	3,157
Total investments in affiliates	$ 8,932	$ 7,461
Net income from equity investments	$ 550	$ 488

Dividends received from these investments amounted to $300 million in 2004 and $259 million in 2003. The Company's share of undistributed earnings of the equity affiliates totaled $1,262 million and $947 million at December 31, 2004 and 2003, respectively.

Accounts and notes receivable in the Consolidated Balance Sheet included $41 million and $112 million at December 31, 2004, and 2003, respectively, of amounts due from equity investees. Accounts payable included $70 million and $55 million at December 31, 2004, and 2003, respectively, of amounts due to equity investees.

During 2004, a subsidiary of the Company acquired an additional 35,596 shares of preferred stock of an affiliated company for $1,450 million. This investment is included in investments in affiliates in the Consolidated Balance Sheet.

Note 8 Litigation and Contingencies

The Company is subject to numerous federal, state and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the Company to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the Company or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the Company may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the reasonably estimable future costs of probable environmental obligations, including the Company's probable costs for obligations for which the Company is jointly and severally liable, and for assets or businesses that were previously disposed, have been provided for in the Company's results of operations. These estimated costs represent the amount of expenditures expected to be incurred in the future to remediate sites with known environmental obligations. The accrued liability represents a reasonable best estimate of the Company's remediation liability. While the amounts of future costs could be significant and could be material to the Company's results of operations in the period in which they are recognized, the Company does not expect these costs to have a material effect on the Company's financial position or liquidity.

There were contingent liabilities at December 31, 2004, and 2003 in respect of guarantees and indemnities entered into as part of the ordinary course of the Company's business. No material losses are likely to arise from such contingent liabilities.

The Company generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the Company. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

Note 9 Short-Term Obligations

The Company's short-term obligations are primarily comprised of commercial paper and variable rate industrial revenue municipal bonds. At December 31, 2004, and 2003, commercial paper borrowings amounted to $1,083 million and $1,102 million and variable rate industrial revenue municipal bonds amounted to $1,616 million and $1,601 million, respectively. Variable rate industrial revenue municipal bonds outstanding at December 31, 2004 had maturities extending through 2038. While the bonds have specified maturities, holders can demand repayment on interest reset dates. Bonds tendered for repayment are generally remarketed.

In December 2003, the Company received approximately $300 million as an advance payment for natural gas that will be delivered over a ten-year period. The payment and accrued interest are included in short-term obligations in the Consolidated Balance Sheet. This obligation is reduced, and revenue recognized, as the natural gas is delivered to the purchaser. The balance, including accrued interest, was $292 million at both December 31, 2004 and 2003.

Note 10 Accounts Payable

Accounts payable at December 31, 2004, and December 31, 2003, included liabilities in the amount of $282 million and $299 million, respectively, for checks issued in excess of related bank balances but not yet presented for collection.

Note 11 Long-Term Debt

The Company's non-affiliate long-term debt resides principally with two subsidiaries, BP Company North America Inc. and BP Canada Energy Company. The components of long-term debt and year-end interest rates are summarized as follows.

Millions of Dollars - December 31	2004	2003
Non-Affiliate		
Borrowings by BP Company North America Inc. and subsidiaries		
6.25% Notes due 2004	$ -	$ 196
8.75% Notes due 2005	142	144
10.88% Notes due 2005	418	431
8.38% to 8.50% Notes due 2005 through 2007	163	165
6.50% to 6.96% Notes due 2006 through 2009	275	273
6.50% Notes due 2007	299	299
6.00% Notes due 2008	426	426
5.90% Notes due 2009	398	394
9.13% Notes due 2011	275	278
8.50% Notes due 2012	189	201
8.25% to 9.00% Notes due 2021 through 2022	84	90
8.75% to 9.13% Notes due 2031 through 2032	103	103
7.00% Notes due 2038	145	145
8.38% to 8.61% Series B Notes due 2011 through 2012	167	163
5.00% to 7.38% Bonds due 2008 through 2021	108	53
Other	50	51
Borrowings by BP Canada Energy Company		
6.75% Debentures due 2005	300	300
8.98% Bonds due 2005	200	200
3.38% to 3.63% Debentures due 2007 through 2009	550	555
6.05% Debentures due 2030	88	64
Other	574	616
	4,954	5,147
Less current maturities	1,154	205
	$ 3,800	$ 4,942

Substantially all of the Company's non-affiliate debt, including the short-term obligations described in Note 9, has been guaranteed by BP.

Annual maturities of non-affiliate long-term debt during the next five years are $1,154 million in 2005, $197 million in 2006, $793 million in 2007, $505 million in 2008, and $769 million in 2009.

Millions of Dollars - December 31	2004	2003
Affiliate		
1.93% BP Capital loan due 2004	$ -	$ 169
2.30% to 3.79% BP Capital loan due 2004 through 2008	969	499
6.96% Revolving Credit Facility due 2005	1,401	-
2.67% to 7.06% BP International loans due 2005 through 2007	456	-
3.33% to 6.55% BP Asia Pacific loan due 2005 through 2010	218	189
1.87% CH-Twenty loan due 2008	1,103	1,093
5.40% BP International loan due 2011	422	391
2.67% BP Capital loan due 2016	49	30
Other	54	148
	4,672	2,519
Less current maturities	2,350	461
	$ 2,322	$ 2,058

At December 31, 2004, the Company had a short-term revolving credit facility with BP International Limited (BP International), a wholly owned subsidiary of BP, in the amount of $1,520 million. Borrowings under the facility at December 31, 2004 were $1,401 million.

In addition, at December 31, 2004, the Company had long-term loan facilities with BP International in the amount of $2,662 million, BP Capital VOF (BP Capital), a wholly owned subsidiary of BP, in the amount of $1,747 million, CH-Twenty Inc. (CH-Twenty), a wholly owned subsidiary of BP, in the amount of $1,332 million and BP Asia Pacific Holdings Ltd (BP Asia Pacific), a wholly owned subsidiary of BP, in the amount of $252 million.

Annual maturities of affiliate long-term debt during the next five years are $2,350 million in 2005, $313 million in 2006, $186 in 2007, $1,153 in 2008 and $0 in 2009.

Note 12 Non-Current Accruals and Reserves

Millions of Dollars – December 31	2004	2003
Accrued dismantlement, restoration and reclamation costs	$ 1,596	$ 1,588
Other environmental accruals	873	899
Employee benefit accruals	2,285	2,412
Other non-current liabilities	1,513	1,585
	$ 6,267	$ 6,484

As discussed in Note 1, the Company adopted SFAS 143 effective January 1, 2003. Upon adoption of SFAS 143, the existing provision for dismantlement, restoration and reclamation costs was reversed, and a new provision under SFAS 143 was recognized.

The following table summarizes the changes to the Company's accrued dismantlement, restoration and reclamation costs:

Millions of Dollars	2004	2003
Balance at January 1	$ 1,588	$ 1,259
Liabilities incurred	131	486
Liabilities settled	(204)	(243)
Accretion expense	89	85
Revisions in estimated cash flows	(8)	1
Balance at December 31	$ 1,596	$ 1,588

Note 13 Leases

The Company leases various types of properties, including service stations, tankers, buildings, railcars and other facilities, some of which are subleased to others. Some of the leases and subleases provide for contingent rentals based on refined product throughput.

Summarized below, as of December 31, 2004, are future minimum rentals payable and related sublease rental income for non-cancelable capital and operating leases.

Millions of Dollars	Capital Leases Rentals Payable	Operating Leases Rentals Payable	Operating Leases Rental Income
2005	$ 39	$ 488	$ 54
2006	32	376	39
2007	26	298	34
2008	26	265	32
2009	27	239	31
Thereafter	107	939	98
Total minimum lease payments	257	$ 2,605	$ 288
Less - amounts representing interest	89		
Capitalized lease obligations	$ 168		
Current	$ 26		
Long-term	142		
	$ 168		

Rental expense and related rental income applicable to operating leases are summarized below.

Millions of Dollars – Year Ended December 31	2004	2003
Minimum rental expense	$ 598	$ 544
Less - related rental income	46	51
Net rental expense	$ 552	$ 493

Note 14 Foreign Currency

A foreign currency loss of $15 million was reflected in income in 2004, compared with a gain of $830 million in 2003. In addition, a net translation gain of $214 million and loss of $33 million for 2004 and 2003, respectively, were reflected as foreign currency translation adjustments in shareholder's equity.

Note 15 Interest Expense

The Company capitalizes interest cost related to the financing of major projects under development. All other interest is expensed as incurred.

Millions of Dollars – Year Ended December 31	2004	2003
External financing	$ 419	$ 430
Affiliates	1,156	694
Other	48	12
	1,623	1,136
Less - capitalized interest	137	107
Net interest expense	$ 1,486	$ 1,029

Affiliate interest expense primarily results from the Company's affiliate borrowings. In addition, certain affiliate accounts payable and other amounts due to affiliates are interest bearing.

Note 16 Research and Development Expenses

Research and development costs are expensed as incurred and amounted to $203 million in 2004 and $149 million in 2003.

Note 17 Taxes

Millions of Dollars – Year Ended December 31	2004	2003
Income tax expense (benefit)		
Federal		
Current	$ 1,846	$ 1,058
Deferred	(43)	(109)
Foreign		
Current	2,077	1,808
Deferred	(110)	(385)
State and Local		
Current	202	172
Deferred	25	(37)
	$ 3,997	$ 2,507

The provision for income taxes differs from the amount computed by applying the statutory income tax rate as follows.

Millions of Dollars – Year Ended December 31	2004	2003
Pre-tax income:		
U.S. source	$ 6,486	$ 4,219
Foreign source	4,681	5,042
	$ 11,167	$ 9,261
Income tax provision at U.S. statutory rates	$ 3,908	$ 3,241
Foreign taxes, net of Federal income tax benefit	329	(395)
State income taxes, net of Federal income tax benefit	148	87
Tax credits	(61)	(57)
Carryforward utilization and prior tax year adjustment	(396)	(355)
Other	69	(14)
	$ 3,997	$ 2,507

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Millions of Dollars – Year Ended December 31	2004	2003
Taxes other than income taxes		
Excise	$ 7,314	$ 7,176
Production and severance	649	556
Real estate, personal property and other	177	146
	$ 8,140	$ 7,878

The Company's results of operations are included in the consolidated federal income tax return filed by BP America. Federal income tax payments are made by, and any related refunds are received by, BP America. The Company's federal income tax provision is based upon the regular taxable income of the Company, with applicable current and deferred income taxes determined as if the Company filed its tax return on a separate return basis.

At December 31, 2004, and 2003, the major components of deferred tax assets and liabilities were as follows.

Millions of Dollars – Year Ended December 31	2004	2003
Deferred tax liabilities		
Accelerated depreciation, depletion and amortization	$ 12,425	$ 12,634
Other	1,501	1,189
	13,926	13,823
Deferred tax assets		
Tax credit carryforwards	536	488
Postretirement benefits	161	270
Other employee benefits	680	615
Environmental and restoration costs	914	969
Other	255	38
Gross deferred tax assets	2,546	2,380
Deferred tax asset valuation allowance	(536)	(488)
	2,010	1,892
Net deferred tax liability	$ 11,916	$ 11,931

Undistributed earnings of certain foreign subsidiaries and joint venture companies aggregated $1,982 million on December 31, 2004, which, under existing law, will not be subject to US tax until distributed as dividends. The Company currently intends to indefinitely reinvest $1,260 million of those earnings in foreign operations. The remainder is anticipated to be distributed to the Company. Any taxes paid to foreign governments on those earnings may be used in whole or in part as credits against the US tax on any dividends distributed from such earnings. It is not anticipated that any incremental US tax will result upon distribution.

The Company has $536 million of foreign tax credit carryforwards for US income tax purposes. If unused, these credits are scheduled to expire in 2009 through 2014.

Note 18 Pension and Other Postretirement Benefits

The Company's parent, BP America, and its subsidiaries have a number of defined benefit pension plans covering most employees. The Company and its subsidiaries participate in these plans and the Company is the sponsor of the plans.

Plan benefits are generally based on length of service and level of compensation. Substantially all of the costs associated with the plans are borne by BP America and its subsidiaries. Contribution amounts are determined by independent actuaries using an actuarial cost method that has an objective of providing an adequate fund to meet pension obligations as they mature.

In addition, BP America and its subsidiaries provide certain health care and life insurance benefits for retired employees. Costs borne by the Company for retirees are based on age and length of service at retirement. The health care benefits are provided through insured and self-insured plan arrangements.

The amounts in the following tables relate to the BP America plans. The Company is charged its proportionate share of costs under the plans and reflects its proportionate share of assets and obligations in its Consolidated Balance Sheet.

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	Pension Benefits		Postretirement Benefits	
Millions of Dollars	**2004**	**2003**	**2004**	**2003**
Change in benefit obligation				
Obligation at beginning of year	$ 8,126	$ 7,078	$ 4,182	$ 4,345
Service cost	219	183	61	56
Interest cost	468	455	243	262
Acquisitions	21	-	13	-
Divestments	(145)	-	-	-
Plan amendments	-	13	(4)	(648)
Settlements, curtailments & other	-	(11)	(19)	(7)
Benefits paid	(328)	(324)	(217)	(220)
Settlements paid	(274)	(364)	-	-
Actuarial loss (gain)	173	1,096	(516)	394
Obligation at end of year	$ 8,260	$ 8,126	$ 3,743	$ 4,182
Change in plan assets				
Fair value at beginning of year	$ 7,167	$ 4,391	$ 33	$ 33
Acquisitions	7	-	-	-
Divestments	(62)	-	-	-
Actual return on plan assets	957	1,178	2	5
Employer contributions	56	2,256	-	-
Benefits paid	(307)	(305)	(5)	(5)
Settlement payments	(262)	(353)	-	-
Fair value at end of year	$ 7,556	$ 7,167	$ 30	$ 33

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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Millions of Dollars	Pension Benefits 2004	Pension Benefits 2003	Postretirement Benefits 2004	Postretirement Benefits 2003
Reconciliation of funded status				
Funded status	$ (704)	$ (959)	$ (3,713)	$ (4,149)
Unrecognized transition amount	(2)	(2)	-	-
Unrecognized prior service cost	81	84	(582)	(651)
Unrecognized net loss	3,592	4,055	1,165	1,843
Net amount recognized	$ 2,967	$ 3,178	$ (3,130)	$ (2,957)
Balance sheet components				
BP America				
Prepaid benefit cost	$ 3,115	$ 3,354	$ -	$ -
Accrued benefit liability	(433)	(484)	(3,130)	(2,957)
Intangible asset	18	20	-	-
Accumulated other comprehensive income	267	288	-	-
Net amount recognized	$ 2,967	$ 3,178	$ (3,130)	$ (2,957)
Components of net periodic cost				
BP America				
Service cost	$ 219	$ 183	$ 61	$ 56
Interest cost	468	455	243	262
Expected return on plan assets	(600)	(489)	(2)	(2)
Settlements, curtailments and other	(1)	4	(2)	(11)
Amortization of unrecognized transition obligation	(1)	-	-	-
Amortization of prior service cost	7	7	(70)	(36)
Amortization of unrecognized net loss	244	138	141	113
Net periodic cost	$ 336	$ 298	$ 371	$ 382

Employer contributions and benefit payments for unfunded plans are not included in the change in plan assets. Such benefits are paid out of general corporate assets.

The BP America accumulated benefit obligation for all defined benefit pension plans was $7,700 million and $7,542 million at December 31, 2004 and 2003, respectively.

The BP America accumulated benefit obligation and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were $699 million and $384 million, respectively, as of December 31, 2004, and were $891 million and $475 million, respectively, as of December 31, 2003.

The BP America projected benefit obligation and fair value of plan assets for pension plans with projected benefit obligations in excess of plan assets were $8,260 million and $7,556 million, respectively, as of December 31, 2004 and were $8,126 million and $7,167 million, respectively, as of December 31, 2003.

The decrease in the minimum liability for BP America, included in its other comprehensive income, for the years ended December 31, 2004 and 2003 amounted to $21 million and $2,928 million, respectively.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act) was enacted in the US. The provisions of the Medicare Act provide for a federal subsidy for plans that provide prescription drug benefits to Medicare-eligible retired employees and meet certain qualifications. Alternatively, the Medicare Act allows prescription drug plan sponsors to coordinate with the Medicare benefit. As a result of the Medicare Act, the postretirement benefit obligation was reduced by $577 million at December 31, 2004. The reduction in the postretirement obligation was recognized as an actuarial gain.

During 2003, BP America revised certain postretirement benefit plan provisions relating to retiree medical benefits. As a result of these plan amendments, the postretirement benefit plan obligation was reduced by $648 million.

Assumptions

	Pension Benefits		Postretirement Benefits	
	2004	**2003**	**2004**	**2003**
Weighted-average assumptions as of December 31				
Used to determine benefit obligations				
Discount rate	5.75%	6.00%	5.75%	6.00%
Compensation increase	4.00	4.00	-	-
Used to determine net periodic benefit cost				
Discount rate	6.00%	6.75%	6.00%	6.75%
Expected return on assets	8.00	8.00	8.00	8.00
Compensation increase	4.00	4.00	-	-

The expected return on plan assets reflects management's expectations of the long-term average returns of each asset class, weighted by the anticipated allocation of pension assets to that asset class. Various independent market forecasts and information are considered when developing the expected return including long-term historical returns, current and expected market conditions and investment strategy.

	Beneficiaries Under 65		Beneficiaries Over 65	
	2004	**2003**	**2004**	**2003**
Assumed health care cost trend rates at December 31				
Health care cost trend rate assumed for next year	9%	11%	12%	14%
Rate to which the cost trend rate is assumed to decline - the ultimate trend rate	5%	5%	6%	6%
Year that the rate reaches the ultimate trend rate	2008	2009	2008	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for postretirement benefit plans. A one-percentage point change in assumed health care cost trend rates would have the following effects.

	One-percentage point	
Millions of Dollars	**Increase**	**Decrease**
Effect on total service and interest cost for 2004	$ 50	$ (39)
Effect on year end 2004 postretirement benefit obligation	454	(371)

Plan Assets

Pension plan asset allocations at December 31, 2004 and 2003, by asset category, are as follows.

	2004		2003	
Millions of Dollars - December 31	**Assets**	**Percent**	**Assets**	**Percent**
Asset Category				
Domestic equity	$ 4,092	54%	$ 3,919	55%
International equity	1,800	24	1,593	22
Fixed income	1,168	15	1,109	15
Cash	67	1	149	2
Other	429	6	397	6
Total	$ 7,556	100%	$ 7,167	100%

Pension plan assets are held in a trust. The primary objective of the trust is to accumulate a pool of assets sufficient to meet the obligations of the various plans. The Company invests the assets of the trust in a manner consistent with its fiduciary obligations and principles that reflect current practices in portfolio management.

In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolio is diversified by asset class exposure. The long-term target asset allocation policy for the majority of BP America plans is as follows.

Asset Category	Policy Target
Domestic equity	55%
International equity	20
Fixed income	18
Cash	-
Other	7

Variations from the target policy mix are adjusted through the allocation of annual contributions and withdrawals, transfers between asset classes and through derivatives. Direct investment of trust assets in either securities or real property of the Company or any affiliate is generally prohibited.

Postretirement benefit plan asset allocations at December 31, 2004 and 2003, by asset category, are as follows.

	2004		2003	
Millions of Dollars - December 31	**Assets**	**Percent**	**Assets**	**Percent**
Asset Category				
Equities	$ 21	70%	$ 24	73%
Fixed income	9	30	9	27
Total	$ 30	100%	$ 33	100%

Cash Flows

Contributions

The Company does not expect to make any contributions to its pension plans during 2005.

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, and the expected subsidy receipts through 2014 are as follows.

Millions of Dollars - Year Ended December 31	Pension Benefits	Postretirement Benefits	Subsidy Receipts
2005	$ 567	$ 253	$ -
2006	585	237	24
2007	606	240	25
2008	623	239	27
2009	638	242	28
Years 2010 through 2014	3,862	1,250	155

Defined Contribution Plans

Most employees are eligible to participate in defined contribution plans by contributing a portion of their compensation. The Company and its subsidiaries match contributions up to specified percentages of each employee's compensation. Company contributions were $138 million in 2004 and $127 million in 2003.

Note 19 Transactions with BP and Subsidiaries

The Company and its subsidiaries have transactions in the ordinary course of business with its parent and with other members of the BP group. Such transactions include the sale of crude oil, petroleum products, chemicals and other goods and services amounting to $19,390 million in 2004 and $14,356 million in 2003, and purchases of similar items amounting to $26,360 million in 2004 and $18,253 million in 2003. In addition, the Company engaged in transactions with BP group companies resulting in other operating revenues of $396 million in 2004 and $362 million in 2003.

BP group financing transactions resulted in interest income of $1,607 million and interest expense of $1,156 million in 2004, compared with $1,045 million interest income and $694 million interest expense in 2003. This interest expense results from long-term debt - affiliates. In addition, certain accounts payable - affiliates and amounts due to affiliates balances are also interest bearing.

A subsidiary of the Company paid dividends on preferred stock of a subsidiary company to the BP group of $892 million and $839 million in 2004 and 2003, respectively. The preferred stock relates to the 2001 and 2003 transfers of various assets, liabilities and ownership interests in certain other BP subsidiaries to subsidiaries of the Company in exchange for preferred stock of BP Company, a wholly owned subsidiary of the Company. Additionally, in 2004 the Company paid dividends on its common stock to the BP group of $35 million. No dividends were paid on the Company's common stock in 2003.

The Company received dividends from the BP group of $96 million and $57 million in 2004 and 2003, respectively.

In December 2003, the Company and BP International entered into a Services Agreement (the Services Agreement) acknowledging that each routinely provides certain administrative, financial, professional and other services for the benefit of the other party. Under the Services Agreement, which provided a January 1, 2003 commencement date, the Company and BP International agreed to continue to provide such services in consideration for which they shall receive reimbursement for all direct and indirect costs incurred in the provisioning of the services. Accordingly, in 2004 and 2003 the Company recorded net charges of $322 million and $136 million, respectively, related to services received from BP International during the year. Furthermore, the Company and BP International agreed to reimburse each other for services rendered during 2001 and 2002. Accordingly, the Company recorded an additional net charge of $262 million against earnings in 2003.

In 2001, the Company entered into an option agreement with BP under the terms of which the Company's investment in Lukoil would be transferred to BP at a specified price. The option agreement, which included an interest rate swap, was entered into in connection with BP's issuance of debt convertible into Lukoil shares. In February 2003, in connection with the holders of the debt electing to exchange the BP bonds for Lukoil shares, the Company's remaining investment in Lukoil was transferred to BP. The transfer resulted in a pre-tax gain of $66 million, which is included in the Company's sales and operating revenue for 2003.

Note 20 Segment and Geographic Data

The Company operates worldwide in the petroleum and chemical industries, in four industry segments. Reportable segments are differentiated by the nature of the activities that each undertakes and the products they manufacture and market.

Exploration and Production activities include oil and natural gas, exploration, field development and production, gas processing and marketing and pipeline transportation. Refining and Marketing activities include oil supply and trading, refining and marketing, and the marketing of Canadian crude oil and sulfur. The Petrochemicals segment manufactures and sells various petroleum-based chemical products. Gas, Power and Renewables activities include marketing and trading of natural gas, liquefied natural gas, natural gas liquids and power, the development of international opportunities that monetize upstream gas resources and involvement in select power projects.

Corporate and Other activity is principally comprised of interest and general corporate expenses, the results of investments in real estate interests, technology companies and other activities.

In 2004, the Company realigned its segment information to include as part of its Gas, Power and Renewables segment the Company's natural gas liquids operations that were previously reported within the Exploration and Production segment. Segment information for 2003 has been restated to reflect this realignment.

Intersegment and intergeographic sales are accounted for at prices that approximate market prices. Income taxes are generally assigned to the operations that give rise to the tax effects.

Identifiable assets are those used in the operations of each segment or area, including intersegment or intergeographic receivables. Corporate assets include cash, marketable securities, notes and amounts due from affiliates, and the unamortized cost of purchased tax benefits.

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Information by Industry Segment

Millions of Dollars	Exploration and Production	Refining and Marketing	Petro-chemicals	Gas, Power and Renewables	Corporate and Other	Total
Year 2004						
Revenue from external customers	$ 10,007	$ 72,165	$ 8,981	$ 69,597	$ 665	$ 161,415
Excise taxes	28	7,286	-	-	-	7,314
Intersegment revenues	11,058	2,401	9	2,157	-	
Equity in earnings of others	360	47	78	2	63	550
Total revenues						$ 169,279
Income before interest and income taxes	$ 8,983	$ 1,567	$ (183)	$ 816	$ (326)	$ 10,857
Interest expense	-	-	-	-	(1,486)	(1,486)
Interest income	-	-	-	-	1,796	1,796
Income tax (provision) benefit	(3,113)	(233)	289	(447)	(493)	(3,997)
Dividends on preferred stock of subsidiary	-	-	-	-	(892)	(892)
Minority interest	(281)	(412)	(33)	-	-	(726)
Net income (loss)	$ 5,589	$ 922	$ 73	$ 369	$ (1,401)	$ 5,552
Investments in affiliates	$ 7,837	$ 498	$ 546	$ 36	$ 15	$ 8,932
Goodwill	4,705	1,987	1	26	16	6,735
Other segment assets	41,370	15,092	8,165	13,419	93,878	171,924
Total assets						$ 187,591
Depreciation and related charges	$ 3,885	$ 1,141	$ 1,034	$ 165	$ 26	$ 6,251
Capital expenditures	5,055	1,044	352	156	84	6,691

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Millions of Dollars	Exploration and Production	Refining and Marketing	Petro-chemicals	Gas, Power and Renewables	Corporate and Other	Total
Year 2003						
Revenue from external customers	$ 9,462	$ 60,426	$ 7,616	$ 52,900	$ 750	$ 131,154
Excise taxes	25	7,151	-	-	-	7,176
Intersegment revenues	9,345	1,444	23	2,092	-	
Equity in earnings of others	342	71	24	2	49	488
Total revenues						$ 138,818
Income before interest and income taxes	$ 7,713	$ 78	$ 189	$ 492	$ 705	$ 9,177
Interest expense	-	-	-	-	(1,029)	(1,029)
Interest income	-	-	-	-	1,113	1,113
Income tax (provision) benefit	(2,305)	34	89	(202)	(123)	(2,507)
Dividends on preferred stock of subsidiary	-	-	-	-	(839)	(839)
Minority interest	(306)	56	-	-	-	(250)
Cumulative effect of accounting change	-	-	-	-	(1)	(1)
Net income (loss)	$ 5,102	$ 168	$ 278	$ 290	$ (174)	$ 5,664
Investments in affiliates	$ 6,066	$ 520	$ 819	$ 37	$ 19	$ 7,461
Goodwill	4,705	1,987	1	26	16	6,735
Other segment assets	41,889	14,526	9,301	9,535	73,996	149,247
Total assets						$ 163,443
Depreciation and related charges	$ 5,040	$ 996	$ 440	$ 114	$ 46	$ 6,636
Capital expenditures	5,262	1,179	345	204	81	7,071

Information by Geographic Area

	2004		2003	
Millions of Dollars	Revenues	Property, Plant & Equipment	Revenues	Property, Plant & Equipment
United States	$ 133,036	$ 34,692	$ 107,789	$ 35,066
Canada	27,676	2,274	21,660	2,615
Europe	2,909	5,197	2,715	5,209
Central & South America	2,279	2,622	3,213	2,418
Other	3,379	6,929	3,441	6,044
Total	$ 169,279	$ 51,714	$ 138,818	$ 51,352

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION

2003 Restated for Reorganization

OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The tables that follow provide supplemental information about oil and gas exploration and production activities as defined by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." This information excludes activities associated with the marketing of natural gas. Gains or losses from retirements or dispositions of property, plant and equipment are also excluded.

Results of Operations for Oil and Gas Producing Activities

Millions of Dollars	United States	Canada	Europe	Central & South America	Other	World-wide
2004						
Oil and gas production revenues:						
From consolidated subsidiaries	$ 9,058	$ 1,044	$ 135	$ 821	$ -	$ 11,058
From unconsolidated affiliate and unaffiliated entities	726	65	2,294	1,575	1,958	6,618
Total revenues	9,784	1,109	2,429	2,396	1,958	17,676
Production costs:						
Taxes other than income	277	2	78	231	61	649
Other production costs	1,094	156	273	135	565	2,223
Exploration expenses	284	31	10	63	42	430
Depreciation, depletion and amortization expense	2,296	157	604	455	181	3,693
Other costs	1,251	353	36	73	136	1,849
Total costs	5,202	699	1,001	957	985	8,844
Operating profit	4,582	410	1,428	1,439	973	8,832
Income tax expense	1,343	170	503	746	391	3,153
Minority interest	-	-	96	148	37	281
Results of operations	$ 3,239	$ 240	$ 829	$ 545	$ 545	$ 5,398
Equity Interest						$ 242

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Millions of Dollars	United States	Canada	Europe	Central & South America	Other	World-wide
2003						
Oil and gas production revenues:						
From consolidated subsidiaries	$ 7,221	$ 1,112	$ 117	$ 782	$ -	$ 9,232
From unconsolidated affiliate and unaffiliated entities	2,301	29	1,938	1,228	2,008	7,504
Total revenues	9,522	1,141	2,055	2,010	2,008	16,736
Production costs:						
Taxes other than income	264	1	55	187	49	556
Other production costs	1,052	226	249	209	312	2,048
Exploration expenses	178	26	24	41	84	353
Depreciation, depletion and amortization expense	2,927	147	776	268	658	4,776
Other costs	1,383	296	34	117	52	1,882
Total costs	5,804	696	1,138	822	1,155	9,615
Operating profit	3,718	445	917	1,188	853	7,121
Income tax expense	1,238	154	217	433	118	2,160
Minority interest	-	-	82	197	27	306
Results of operations	$ 2,480	$ 291	$ 618	$ 558	$ 708	$ 4,655
Equity Interest						$ 298

Oil and gas production revenues reflect the market prices of net production sold or transferred, with appropriate adjustments for royalties, net profits interest and other contractual provisions. Taxes other than income include production and severance taxes. Other production costs are lifting costs incurred to operate and maintain productive wells and related equipment, including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Also included are operating costs of field natural gas liquids plants. Production costs include related administrative expenses and depreciation applicable to support equipment associated with production activities.

Exploration expenses include the costs of geological and geophysical activity, carrying and retaining undeveloped properties and drilling exploratory wells determined to be non-productive. Depreciation, depletion and amortization expense relates to capitalized costs incurred in acquisition, exploration and development activities and does not include depreciation applicable to support equipment. Included in other related costs are significant, non-recurring items and purchases of natural gas for field natural gas liquids plants.

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Income taxes are generally assigned to the operations that give rise to the tax effects. Results of operations do not include interest expense and general corporate amounts nor their associated tax effects.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is prescribed by SFAS No. 69. The statement requires measurement of future net cash flows through assignment of a monetary value to proved reserve quantities and changes therein using a standardized formula. The amounts shown are based on prices and costs at the end of each period, legislated tax rates and a ten percent annual discount factor. Because the calculation assumes static economic and political conditions and requires extensive judgment in estimating the timing of production, the resultant future net cash flows are not necessarily indicative of the fair market value of estimated proved reserves, but provide a reference point that may assist the user in projecting future cash flows.

Summarized on the following pages is the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2004 and 2003. The amount shown for equity interest represents the Company's proportionate economic interest in the estimated discounted future net cash flows of equity affiliates.

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Millions of Dollars	United States	Canada	Europe	Central & South America	Other	World-wide
December 31, 2004						
Future cash inflows	$ 117,328	$ 7,607	$ 27,519	$ 35,453	$ 44,645	$ 232,552
Future development and production costs	30,477	4,187	8,985	11,407	15,933	70,989
Future income taxes	28,474	1,073	12,455	13,111	8,367	63,480
Future net cash flows	58,377	2,347	6,079	10,935	20,345	98,083
Ten percent annual discount	26,989	991	2,450	5,092	9,824	45,346
Discounted net cash flows	$ 31,388	$ 1,356	$ 3,629	$ 5,843	$ 10,521	$ 52,737
Equity Interest						$ 3,981
December 31, 2003						
Future cash inflows	$ 112,266	$ 9,605	$ 21,420	$ 37,782	$ 31,056	$ 212,129
Future development and production costs	24,828	5,003	7,902	10,687	9,468	57,888
Future income taxes	30,069	1,472	8,140	14,021	5,871	59,573
Future net cash flows	57,369	3,130	5,378	13,074	15,717	94,668
Ten percent annual discount	26,529	1,672	2,112	6,932	7,225	44,470
Discounted net cash flows	$ 30,840	$ 1,458	$ 3,266	$ 6,142	$ 8,492	$ 50,198
Equity Interest						$ 3,112

Minority interest in discounted future net cash flows in Norway, Trinidad, and Algeria approximated $961 million, $1,564 million, and $881 million in 2004 and $713 million, $1,664 million, and $889 million in 2003, respectively.

Future cash inflows are computed by applying the year-end prices of oil and gas to proved reserve quantities as reported under "Estimated Proved Reserves". Future price changes are considered only to the extent provided by contractual arrangements. Future development and production costs are estimated expenditures to develop and produce the proved reserves based on year-end costs and assuming continuation of existing economic conditions. Future income taxes are calculated by applying appropriate statutory tax rates to future pre-tax net cash flows from proved oil and gas reserves less recovery of the tax basis of proved properties, and adjustments for permanent differences.

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Statement of Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table details the changes in the standardized measure of discounted future net cash flows for the two years ended December 31, 2004.

Millions of Dollars	2004	2003
Balance at January 1	$ 50,198	$ 47,779
Changes resulting from:		
Sales and transfers of oil and gas produced, net of production costs	(14,149)	(14,315)
Net changes in prices, and development and production costs	11,870	7,182
Current year expenditures for development	4,431	4,605
Extensions, discoveries and improved recovery, less related costs	2,131	8,224
Sales of reserves in place	(482)	(4,266)
Revisions of previous quantity estimates	(6,597)	(7,375)
Accretion of discount	5,020	4,778
Net change in income taxes	1,108	4,509
Other	(793)	(923)
Balance at December 31	$ 52,737	$ 50,198

The prices of crude oil and natural gas have fluctuated over the past several years, which affects the computed future cash flows over the period shown. Because the price of crude oil and natural gas is likely to remain volatile in the future, price changes can be expected to continue to significantly affect the standardized measure of discounted future net cash flows.

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Estimated Proved Reserves

Net proved reserves of crude oil (including condensate), NGL and natural gas at the beginning and end of 2004 and 2003, with the detail of changes during those years, are presented on the following pages. Reported quantities include reserves in which the Company holds an economic interest under production-sharing and other types of operating agreements with foreign governments. The estimates were prepared by Company engineers and are based on current technology and economic conditions. The Company considers such estimates to be reasonable and consistent with current knowledge of the characteristics and extent of proved production. These estimates include only those amounts considered to be proved reserves and do not include additional amounts that may result from extensions of currently proved areas, or amounts that may result from new discoveries in the future, or from application of secondary or tertiary recovery processes not yet determined to be commercial. Proved developed reserves are those reserves that are expected to be recovered through existing wells with existing equipment and operating methods. The amounts shown for affiliates represent the Company's proportionate economic interest in estimated proved reserves of equity affiliates.

Estimates of proved reserves as of December 31, 2004 reflect year-end prices and, in certain situations, are based on different applications of certain interpretations and regulations of the Securities and Exchange Commission than the estimates that were disclosed in prior years. Estimates of proved reserves for 2003 have not been revised.

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Crude Oil and NGL Reserves

	Consolidated							
Millions of Barrels	United States	Canada	Europe	Central & South America	Other	Total	Equity Interest	World-wide
Proved reserves								
January 1, 2003	2,036	49	452	386	668	3,591	396	3,987
Revisions of previous estimates	(255)	(3)	(1)	(24)	28	(255)	9	(246)
Improved recovery applications	77	-	8	1	2	88	42	130
Extensions, discoveries and other additions	231	-	16	-	222	469	6	475
Sales of reserves in place	(164)	-	(39)	(13)	(24)	(240)	(5)	(245)
Production	(124)	(5)	(47)	(41)	(51)	(268)	(26)	(294)
December 31, 2003	1,801	41	389	309	845	3,385	422	3,807
Revisions of previous estimates	(21)	(6)	46	(61)	(243)	(285)	(4)	(289)
Improved recovery applications	46	-	5	31	10	92	17	109
Extensions, discoveries and other additions	13	1	1	4	140	159	1	160
Sales of reserves in place	(16)	(10)	-	-	-	(26)	-	(26)
Production	(110)	(4)	(43)	(34)	(39)	(230)	(28)	(258)
December 31, 2004	1,713	22	398	249	713	3,095	408	3,503
Proved developed reserves								
December 31, 2002	853	47	346	227	266	1,739	220	1,959
December 31, 2003	713	39	291	187	220	1,450	261	1,711
December 31, 2004	770	21	283	142	181	1,397	261	1,658

Minority interest in proved reserves for 2004 and 2003 included 203 million and 208 million barrels of crude oil, respectively.

BP CORPORATION NORTH AMERICA INC. AND SUBSIDIARIES

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Natural Gas Reserves

Billions of Cubic Feet	Consolidated United States	Consolidated Canada	Consolidated Europe	Consolidated Central & South America	Consolidated Other	Consolidated Total	Equity Interest	World-wide
Proved reserves								
January 1, 2003	12,333	1,556	1,269	16,050	6,115	37,323	2,945	40,268
Revisions of previous estimates	(777)	(248)	32	(672)	(423)	(2,088)	186	(1,902)
Improved recovery applications	2,083	1	17	259	27	2,387	35	2,422
Extensions, discoveries and other additions	293	61	1,213	3	-	1,570	12	1,582
Purchases of reserves in place	1	-	-	-	-	1	-	1
Sales of reserves in place	(900)	(12)	(250)	-	(1,229)	(2,391)	(481)	(2,872)
Production	(1,130)	(154)	(189)	(622)	(316)	(2,411)	(143)	(2,554)
December 31, 2003	11,903	1,204	2,092	15,018	4,174	34,391	2,554	36,945
Revisions of previous estimates	(5)	(91)	148	(1,782)	222	(1,508)	227	(1,281)
Improved recovery applications	870	4	9	71	67	1,021	22	1,043
Extensions, discoveries and other additions	140	37	5	954	2,714	3,850	-	3,850
Purchases of reserves in place	3	2	-	-	-	5	-	5
Sales of reserves in place	(202)	(92)	-	-	(150)	(444)	-	(444)
Production	(1,007)	(134)	(148)	(706)	(314)	(2,309)	(170)	(2,479)
December 31, 2004	11,702	930	2,106	13,555	6,713	35,006	2,633	37,639
Proved developed reserves								
December 31, 2002	10,074	1,380	1,100	3,218	2,075	17,847	1,506	19,353
December 31, 2003	9,357	1,124	768	2,839	1,576	15,664	1,625	17,289
December 31, 2004	8,432	874	725	3,011	1,832	14,874	1,564	16,438

Minority interest in proved reserves for 2004 and 2003 included 5,505 billion and 5,896 billion cubic feet of natural gas, respectively.

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Capitalized Costs

The following table summarizes capitalized costs for oil and gas exploration and production activities, and the related accumulated depreciation, depletion and amortization.

Millions of Dollars	United States	Canada	Europe	Central & South America	Other	World-wide
December 31, 2004						
Unproved properties						
Gross assets	$ 457	$ 137	$ 182	$ 58	$ 1,185	$ 2,019
Accumulated amortization	181	32	-	35	96	344
Net assets	276	105	182	23	1,089	1,675
Proved properties						
Gross assets	25,040	2,728	11,006	5,542	12,879	57,195
Accumulated depreciation, depletion	5,754	1,583	7,665	3,089	8,584	26,675
Net assets	19,286	1,145	3,341	2,453	4,295	30,520
Net capitalized costs	$ 19,562	$ 1,250	$ 3,523	$ 2,476	$ 5,384	$ 32,195
Equity Interest						$ 3,191
December 31, 2003						
Unproved properties						
Gross assets	$ 436	$ 134	$ 273	$ 86	$ 1,684	$ 2,613
Accumulated amortization	188	26	22	65	98	399
Net assets	248	108	251	21	1,586	2,214
Proved properties						
Gross assets	25,560	3,020	10,408	5,232	12,864	57,084
Accumulated depreciation, depletion	6,409	1,733	6,931	2,852	8,988	26,913
Net assets	19,151	1,287	3,477	2,380	3,876	30,171
Net capitalized costs	$ 19,399	$ 1,395	$ 3,728	$ 2,401	$ 5,462	$ 32,385
Equity Interest						$ 2,525

Minority interest in net capitalized costs approximated $1,837 million and $1,851 million in 2004 and 2003, respectively.

SUPPLEMENTAL INFORMATION (continued)

2003 Restated for Reorganization

Costs Incurred

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire oil and gas properties. Exploration costs include the costs of geological and geophysical activity, carrying and retaining undeveloped properties and drilling and equipping exploratory wells. Development costs include the costs of drilling and equipping development wells, CO_2 and certain other injected materials for enhanced recovery projects and facilities to extract, treat and gather and store oil and gas. Exploration and development costs include administrative expenses and depreciation applicable to support equipment associated with these activities. Costs incurred summarized below include both amounts expensed and capitalized.

Millions of Dollars	United States	Canada	Europe	Central & South America	Other	World-wide
Year 2004						
Property acquisition						
Proved	$ -	$ -	$ -	$ -	$ -	$ -
Unproved	58	5	-	-	13	76
Exploration	273	36	-	117	183	609
Development	2,648	113	318	331	1,021	4,431
Total	$ 2,979	$ 154	$ 318	$ 448	$ 1,217	$ 5,116
Equity Interest						$ 1
Year 2003						
Property acquisition						
Proved	$ -	$ -	$ -	$ -	$ -	$ -
Unproved	-	-	-	-	-	-
Exploration	61	24	55	45	184	369
Development	2,754	100	286	451	1,002	4,593
Total	$ 2,815	$ 124	$ 341	$ 496	$ 1,186	$ 4,962
Equity Interest						$ 44

Minority interest in total costs incurred approximated $269 million and $498 million in 2004 and 2003, respectively.

In mapping the future of BP, we began with a business purpose – a strategy, a set of assets and market positions that gave us scope, scale and potential as a leader in our industry. Today, this model describes us well – but not completely. Now our strategy is being driven further, by a belief that everything we do can – and should – be done better. Our people put this principle of operational excellence to work every day throughout BP. You can see it in the ways we aim to use resources efficiently to deliver sustainable production; confidently act first in a complex marketplace; focus on the most meaningful markets; fulfil our customers' needs; learn from our best practices; and lead by example. All to perform reliably and responsibly on behalf of our shareholders worldwide. At BP, this is how we're making the right choices.

Performance highlights

These tables and charts show the highlights of BP's achievements in 2004. They reflect more than our financial performance. Our strong profitability has allowed us to increase the dividend year on year, and we are continuing to invest in the future. Environmental and safety performance remains a key focus. We continue to make significant financial commitments in the communities in which we operate.

In this Report, BP presents pro forma results in addition to its reported results, to enable shareholders to evaluate better our performance against that of our competitors. The pro forma result is replacement cost profit excluding acquisition amortization as defined in footnote [b] to the reconciliation table *(below)*. Both the pro forma result and replacement cost profit include exceptional items and non-operating items as defined in footnote [a] to the reconciliation table *(below)*. The pro forma result has been derived from our UK GAAP accounting information but is not in itself a recognized UK or US GAAP measure. BP will discontinue pro forma reporting at the time it adopts International Financial Reporting Standards with effect from the first quarter of 2005. References within *BP Annual Report and Accounts 2004* to 'result' are to pro forma results. References to 'capital employed', 'operating capital employed' and 'net debt plus equity' are to these measures on a pro forma basis that excludes the fixed asset revaluation adjustment and goodwill consequent upon the Atlantic Richfield Company (ARCO) and Burmah Castrol acquisitions in 2000. 'Return', 'return on average capital employed' and the 'net debt ratio' (net debt/net debt plus equity) refer to ratios calculated using these measures.

The financial information for 2003 has been restated to reflect (a) the transfer of natural gas liquids (NGLs) operations from the Exploration and Production segment to Gas, Power and Renewables on 1 January 2004; (b) the adoption by the group of Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) with effect from 1 January 2004; and (c) the adoption by the group of Urgent Issues Task Force Abstract No. 38 'Accounting for ESOP Trusts' with effect from 1 January 2004.

Key financial measures — $ million

	2004	2003
Pro forma result	16,208	12,858
Replacement cost profit	14,088	10,466
Historical cost profit	15,731	10,482
Per ordinary share – cents		
Pro forma result	74.27	57.99
Replacement cost profit	64.55	47.20
Historical cost profit	72.08	47.27
Dividends per ordinary share – cents	29.45	26.00
– pence	16.099	15.517
Dividends per ADS – dollars	1.77	1.56

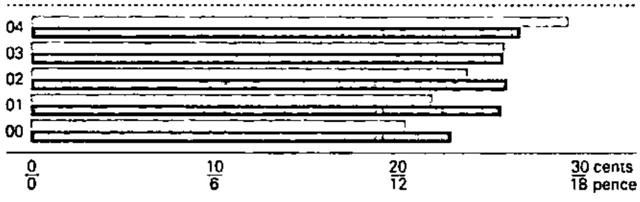
Reconciliation of reported profit/loss to pro forma result — $ million

	2004			2003		
	Reported[a]	Acquisition amortization[b]	Pro forma result	Reported[a]	Acquisition amortization[b]	Pro forma result
Exploration and Production	18,520	1,239	19,759	14,666	1,566	16,232
Refining and Marketing	4,722	881	5,603	2,318	826	3,144
Petrochemicals	(900)	–	(900)	568	–	568
Gas, Power and Renewables	943	–	943	570	–	570
Other businesses and corporate	314	–	314	(184)	–	(184)
Replacement cost profit before interest and tax	23,599	2,120	25,719	17,938	2,392	20,330
Interest and other finance expense	(999)	–	(999)	(1,191)	–	(1,191)
Taxation	(8,282)	–	(8,282)	(6,111)	–	(6,111)
Minority shareholders' interest (MSI)	(230)	–	(230)	(170)	–	(170)
Replacement cost profit	14,088	2,120	16,208	10,466	2,392	12,858
Stock holding gains (losses), net of MSI	1,643			16		
Historical cost profit	15,731			10,482		

[a] Replacement cost profit for the period includes the net profit or loss on the sale of fixed assets and businesses or termination of operations. It also includes non-operating items identified by the group, primarily asset write-downs/impairment, environmental and other provisions and restructuring, integration and rationalization costs. These items do not meet the criteria to be classified as operating exceptional items.

[b] Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions. The results for 2003 and 2004 include accelerated depreciation of the revaluation adjustment in respect of the impairment of former ARCO assets of $381 million and $214 million, respectively.

Dividends per share (cents/pence)

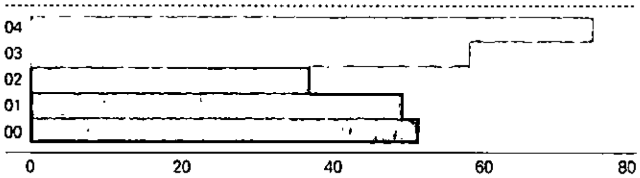


Environmental performance

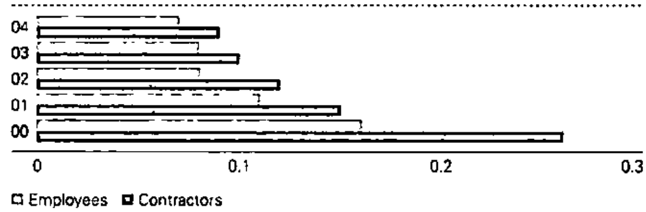
	2004	2003
Greenhouse gas emissions (million tonnes)[a,b]	81.7	83.4
Total number of spills (>1 barrel)[c]	578	635
Percentage of major operations with ISO 14001[d]	100	99

[a] BP share of emissions of carbon dioxide and methane, expressed as an equivalent mass of carbon dioxide.
[b] BP share of TNK-BP emissions is not included.
[c] 1 barrel = 159 litres = 42 US gallons.
[d] ISO 14001 is an international environmental management standard.

Result per share (cents)

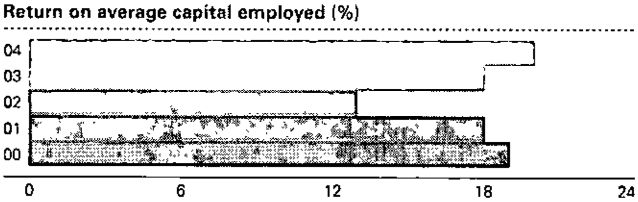


Days away from work case frequency[a,b] (per 200,000 hours)

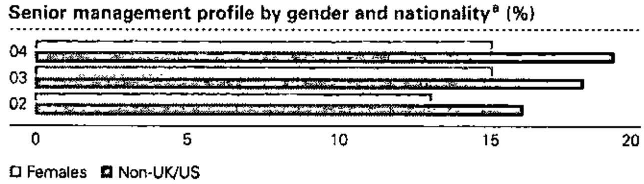


[a] An injury that results in a person being unable to work for a day (shift) or more.
[b] 2002 data excludes Castrol and Veba contractors and Veba employees.

Return on average capital employed (%)



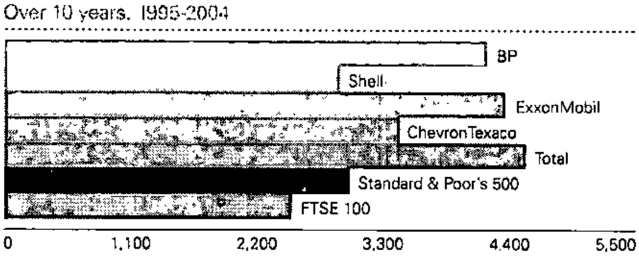
Senior management profile by gender and nationality[a] (%)



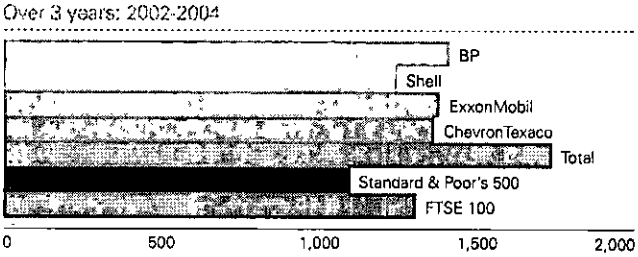
[a] Senior management in 2004 includes the top 610 positions in BP.

Return to shareholders: present value of $1,000 invested ($)

Over 10 years: 1995-2004



Over 3 years: 2002-2004



Shareholder returns comprise annual share price movements, with dividends reinvested, for investments held over the period shown.

Investment in American depositary shares or equivalents for BP, Shell and Total and prime listings for ExxonMobil and ChevronTexaco.

Community investment

By region — $ million

	2004	2003	2002	2001	2000
UK	11.7	12.7	13.9	14.9	15.4
(including UK charities	*3.0*	*2.8*	*3.2*	*4.7*	*4.1)*
Rest of Europe	6.5	8.2	6.2	8.0	5.3
USA	25.7	31.5	46.3	52.9	46.0
Rest of World	43.8	22.0	18.8	18.9	14.9
Total	87.7	74.4	85.2	94.7	81.6

By theme — $ million

	2004	*incl. UK charities 2004*	2003	*incl. UK charities 2003*	2002	2001	2000
Community development	40.3	*0.9*	22.8	*0.9*	24.3	33.3	28.2
Education	33.3	*0.6*	27.1	*0.4*	24.2	29.5	21.3
Environment	6.0	*0.2*	15.4	*1.0*	19.8	15.5	8.3
Arts and culture	4.8	*0.0*	5.6	*0.1*	6.6	8.2	15.0
Other	3.3	*1.3*	3.5	*0.4*	10.3	8.2	8.8
Total	87.7	*3.0*	74.4	*2.8*	85.2	94.7	81.6

Health investment data for 2000-2003 is included in Environment; the equivalent 2004 data is included in Other.

Chairman's letter

Dear Shareholder BP has delivered another excellent set of results for the year. Sustained high oil and gas prices, coupled with advances in operational performance, have resulted in a strong cash flow, accelerating our returns to shareholders in the near term through significant share repurchases. Returning cash in excess of our investment requirements to our shareholders – both through buybacks and our continued pursuit of a progressive dividend policy – is fundamental to our strategy.

Exchange-rate issues – especially the relative weakness of the dollar in the past year – have been felt by those who receive their dividends in sterling. Over the longer term, fluctuating exchange rates generally benefit shareholders on each side of the Atlantic at different times. For instance, in the five-year period from 1996 to 2001, the sterling dividend rose by 58%. The rationale for declaring our dividend in US dollars remains sound, since our principal businesses all trade in that currency. While headline increases in sterling and dollar dividends show a differential, the key element to note is that both are growing.

2004 has seen a rapid acceleration of our buyback programme, with $7.5 billion worth of shares bought back and cancelled during the year. While this has been welcomed by larger and institutional investors, the benefit for all shareholders committed to long-term investment in BP will be felt through the ultimate capital appreciation of their shares. The board keeps its strategy in this area under review to ensure the balance between dividend and buybacks remains appropriate for our owners as a whole.

Against this background, our confidence in the future of the business enables us to make a step change in the fourth-quarter dividend, which I am pleased to confirm as 8.50 cents per share. This makes the annual payment 29.45 cents per share or 16.099 pence per share, an increase in dollar terms over last year of 13% and an increase of 4% in sterling terms.

2004 saw heightened regulatory attention on our industry, not least in the area of the reporting of hydrocarbon reserves. Reserves reporting is an important measure of our performance as it demonstrates the extent to which we are replacing the hydrocarbons we are producing – a particular strength of BP in recent years. As a UK company, our reserves are estimated in accordance with UK accounting practice. These reserves are stated each year in our Annual Report. For US regulatory purposes we report reserves estimates in accordance with the rules of the Securities and Exchange Commission. During the course of the year, the board and its audit committee have exercised considerable scrutiny in this area. In this year's Annual Report, we have included, for the first time, US SEC-based estimates in addition to our UK reserves bookings.

Our business is global and complex, and we are fortunate to have a first-rate executive team to address these challenges. During the year, the executive management team, so ably led by John Browne, has sustained its formidable track record. They have our full confidence and support. I would like to thank John and his team for their exemplary efforts on your behalf in 2004. Our thanks are also due to all 102,900 BP employees around the world for their unremitting effort and the value they have created for our shareholders.

Within a company with such a strong executive management team, it is important that the role of the board is understood. As a board, we are conscious that we oversee the activities of the business in the interests of all our owners. The recent debate on corporate governance has focused on the mechanisms of board process and reporting – ensuring appropriate checks and balances are in place. Against this background, too many company directors have complained that they want to 'move away from corporate governance' and 'get back to running our businesses'.

Correctly, I think, our board recognizes that the primary business of the board *is* corporate governance. Governing BP is not a matter to be driven solely by compliance concerns, but by the business purpose of the company you entrust us to govern on your behalf. Our role as a board therefore focuses on ensuring your interests are promoted and that our business maximizes long-term value for you, our owners.

Ensuring that our business remains nimble and competitive, able to leverage the manifold talents of our managers, is key to the pursuit of that goal. To discharge the trust you place in us as a board, we test the strategic direction of the company's business. We also monitor the operations of the business in pursuit of that strategy to ensure both that BP's activities live out the values we set and also, critically, that shareholder value lies at the heart of all we do.

2004 saw a continuation of our very significant capital investment programme that is key to the long-term future of our business. As a board, we continue to scrutinize the strategic direction of the company, especially as our activities take us to more challenging geographic locations, to ensure that it continues to provide the prospect of the best long-term returns for our shareholders.

In the course of the year, significant work has been undertaken by the chairman's committee and the nomination committee, both of which I chair, as issues of executive and non-executive succession planning and performance come into ever-greater focus. Likewise the remuneration committee, led by Sir Robin Nicholson and his designated successor Dr DeAnne Julius, has been heavily engaged in the development of new incentive plans for our executive directors.

The board performance report on pages 110-115 expands upon the way in which the board and its committees discharge their mandate of governance.

Last year, I commented on board succession and development planning for the coming years. At the forthcoming AGM, two of our senior non-executive directors, Sir Robin Nicholson and Charles (Chuck) Knight, will step down.

Robin has served on the BP board since 1987 and has been an excellent chairman of our remuneration committee. He has had a substantial impact on the board and the company over the past 17 years and been a major contributor to all our board debates; we shall miss his wisdom and insight. On a personal note, I shall miss his sage counsel and technical insight, but am delighted that he has agreed to continue to chair the group's technology advisory committee in the short term.

Chuck Knight also joined the board in 1987. His perspective on corporate practices in the United States and experience as a senior chief executive operating within the US market have proved invaluable, not least as BP has evolved in that marketplace over the past two decades. I will miss his unique contributions to the board's discussions.

I would like to thank both Robin and Chuck on your behalf for all their years of distinguished service.

The endorsement of the strength of our executive team by the invitation extended to Dick Olver to take on the chairmanship of BAE Systems plc was, of course, tinged with sadness at having to bid farewell to a first-rate colleague, who had served the company so well over the past 31 years. We wish Dick well for the future and thank him for his years of dedicated service to BP.

Three new appointments have been made to the board in the last year. Iain Conn has been appointed an executive director. Iain has had a substantial career within BP and is responsible for strategic resources. Sir Tom McKillop, chief executive of AstraZeneca PLC, joined the board in July 2004 and Douglas Flint, chief financial officer of HSBC Holdings plc, joined in January 2005. Each brings his own particular skills and experience to complement those of his fellow directors in the coming years.

The world in which BP operates is ever more complex and challenging. The coming year will see the continued development of our business strategy. I believe your board is well resourced to address shareholders' interests during this period. I look forward to reporting on their successful advance in the years ahead. We have an exciting future together.

Thank you for all your continued support and interest in this company.

Peter Sutherland
Chairman
7 February 2005

Group chief executive's review

Dear Shareholder 2004 was a great year for BP. In terms of overall performance, it was the best since the recent series of mergers and acquisitions.

High demand for energy and higher oil prices certainly contributed to our performance and led to our record financial results. But our success in 2004 was based on more than these external factors.

We showed that we had the capability to deliver our strategy and to translate our scope and scale into competitive advantage. We demonstrated that we had the human talent to increase production, make new discoveries, gain new customers, enhance safety and grow our reputation. Our global workforce worked as a seamless team and I thank every one of them.

As you read this Annual Report and follow our efforts to create value, it may be helpful to understand how we achieve excellent performance.

Our purpose and strategy We begin with our purpose as a group – to provide better goods and services in the form of light, heat, power and mobility to increasing numbers of people. To succeed, we do this in a way that is profitable, sustainable and consistent. This is reflected in value generated for shareholders.

To deliver *profitable* performance, we provide high-quality products in a competitive way – maximizing revenues and minimizing costs.

To deliver *sustainable* performance, we also provide these products in a sustainable way – attracting the best people, accessing large-scale oil and gas resources, building markets in which we enjoy customers' trust while doing business in a mutually advantageous way that brings benefits to everyone concerned – customers, communities, governments, suppliers, citizens – and so generates 'repeat business'.

To deliver *consistent* performance, we invest enough to deliver long-term growth, while balancing this with returns to our shareholders. Too fast a growth rate is unsustainable, while too slow a rate sacrifices competitive advantage. Our analysis gives us confidence that an investment level of around $14 billion is right for 2005 and 2006, taking into account the present level of the dollar and recent sector-specific inflation.

To achieve our purpose, we have a strategy. We make choices about the assets and markets where we operate.

Our business strategy remains unchanged. In Exploration and Production, we seek out long-term assets – the largest, low-cost, new hydrocarbon deposits – while managing the decline of mature fields. In our customer-facing businesses, we look to attract more and more customers through improved quality of products and service. Our challenge is to add new sources of cash flow whose cash returns are at least as good as existing ones.

2004 in context As I wrote last year, we started 2004 with greater scale, common values and a clear strategy. But nothing was a given. We were cautious about our ability to execute – whether our people operating in 100 countries could effectively translate our worldwide assets into world-class performance. We were wary of global developments, including ongoing conflict in Iraq, the threat of terrorism and public mistrust of large companies. And we found ourselves in one of the more volatile oil markets in history, driven by demand and anxiety about supply. Against this backdrop, the team delivered record performance.

As the world's energy market entered uncharted territory in 2004, the subject of the future of energy supply took centre stage. Rising demand – which matched the rate of global economic growth for the first time in 30 years – produced both short-term anxiety about fuel prices and long-term concern about supply. Had there been a fundamental shift in the oil market? Were there enough reserves? What else could disrupt supply? Were companies investing enough to meet demand?

In this uncertain climate, a little history can be reassuring. Clearly, questions over security of supplies have driven oil prices upwards. But, amid all the market disruptions of the past few years, supply has never fallen short of demand. Increased investment by the private sector has led to production gains of more than 15% a year during the last five years. Global production in 2004 rose at the fourth-highest rate in history.

Choosing our goals We execute our strategy against the context of the time. We make plans to achieve three targets:

- To underpin growth by a focus on performance, particularly on cash returns, investing at a rate appropriate for long-term growth.
- To increase dividends.
- To return to shareholders, by way of share buybacks, 100% of free cash flow generated above what is needed for investment and dividends: this generally occurs, all other things being appropriate, when the price of oil exceeds $20 a barrel.

These plans are executed by applying resources and capabilities across the organization.

In last year's report, I wrote that organizational alignment and operational excellence would shape our future as a group and that we had developed a new management framework to harness the energy and imagination of our people. In 2004, we took further steps to embed these common values and processes, clarifying individual accountability. In 2005, we will issue a new code of conduct to ensure that each individual in BP continues to exhibit high and consistent standards of ethical behaviour.

We continue to innovate and apply leading-edge technology. For example, our new Thunder Horse platform in the deepwater Gulf of Mexico breaks many records as the largest floating facility and will operate in the deepest water, with the harshest reservoir pressure and temperature regime.

We also continue to strengthen the development opportunities that we offer to our people. For example, we have the Projects Academy, in which we partner with the Massachusetts Institute of Technology to help people gain best-in-class project management skills.

We measure the views of our staff through a People Assurance Survey. In 2004, this showed a significant rise in

the overall employee satisfaction index, demonstrating an increasing sense of enthusiasm and teamwork among BP's employees.

Reaching new milestones In a year of great success, there were notable operational highlights:

- Our safety record improved for the eighth year running, although tragically we still suffered 11 fatalities among contractors and employees.
- Exploration and Production made new discoveries in Angola, Egypt, the deepwater Gulf of Mexico, Trinidad and Sakhalin Island in Russia and brought on stream three new fields.
- Our production growth of more than 10% was in line with our indicator of a 7% average for 2003-2008.
- Replacement of proved reserves (for subsidiaries and equity-accounted entities) at over 100% exceeded production for the 12th year running. TNK-BP contributed $1.5 billion, after interest and tax, to our result, paid to us $1.9 billion of dividends and increased oil production volumes by 14%.
- In Refining and Marketing, refining margins reached their highest levels since at least 1990. We continued to find ways to maximize our global refining capacity.
- Premium Ultimate fuels have been newly launched in six markets, attracting new customers to these higher-performance, cleaner, higher-margin products.
- BP's retail sales continued to outpace the sector. At our convenience locations worldwide, sales per square metre grew by an average of 3%.
- We entered into agreements to sell liquefied natural gas to the US, China, South Korea and Mexico, and produced growth in sales volumes.
- Our solar business streamlined its operations, tightened its market focus and delivered its first profit.
- We initiated the separation of the Petrochemicals business into two entities, while still achieving record sales volumes through increased plant use and reliability.
- Through disciplined portfolio management, we made $5 billion of divestments.

Through our activities, BP delivered a record result of $16.2 billion in 2004. With cash inflow of $6 billion and cash returns of 35%, our performance continued to allow for strong investment in our long-term growth as well as to return value to investors in the form of higher dividends – 29.45 cents per share in 2004, an increase of 13% year on year – and significant share buybacks, amounting to $7.5 billion in the year.

BP now has the assets, market positions and organizational capability to continue to deliver its unchanged strategy.

We are meeting our three targets, with disciplined investments, increased dividends and excess free cash flow for significant share buybacks.

We have confidence in our ability to perform sustainably, focusing mainly on conventional oil and gas resources, seeking to add value to products and services in customer-facing businesses.

In my many meetings with BP people around the world, I am constantly struck by their commitment to deliver ever-improved performance, but responsibly and with integrity. My role is to provide the framework that guides and encourages them to make the right choices: today, tomorrow and for the long-term future of your company. As always, the best is yet to come.

The Lord Browne of Madingley
Group Chief Executive
7 February 2005

What makes a business choice disciplined?

What turns complexity into clarity?

What connects customer insight to market performance?

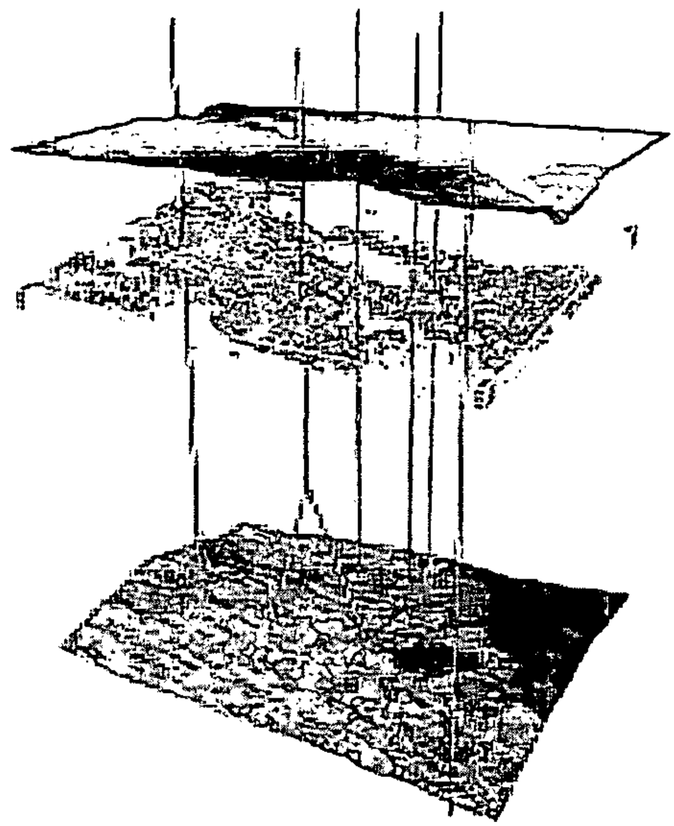
What converts creativity into productivity?

And how do we put our principles into practice?

The fact is, there is no formula for operational excellence. There's no patented system, established path or single way to achieve it. For every company that competes on a global basis, the journey to operational excellence is unique. For BP, operational excellence enables us reliably and responsibly to deliver our strategy. From the assets we've built to the returns we offer our investors – and the ideas we turn into action along the way – individuals and teams across BP are putting operational excellence into practice, making it an organizational principle, not simply an aspiration.

Resourcefulness on a new scale

Our resources business is about renewal. We operate within the world's largest supply-and-demand relationship, a marketplace in which our long-term success depends on the ability of our teams to replace reserves at least as fast as they bring them to market. So how have we done? As we describe later, in each of the last 12 years, we've replaced more than 100% of our production and, at the same time, delivered some of the lowest finding costs in our industry. Developing our resources through operational excellence is converting our scale into profitability. Turning our technologies into discoveries. Bringing our projects into production. Connecting our exceptional people through best practices. And extending the potential of the world's energy resources.



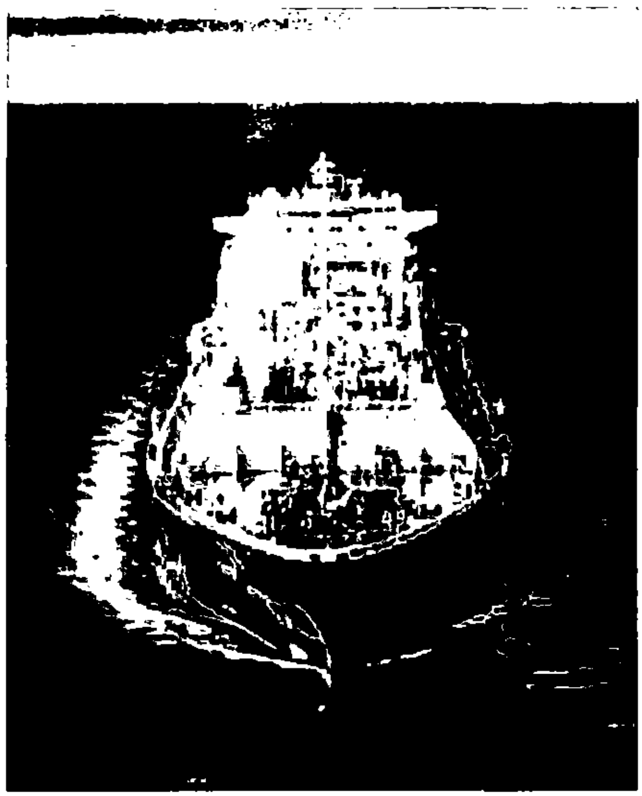
Seeing into the future Discovery never ends. That's a principle our people learned long ago. Even in the most mature oil and gas fields, there is hidden potential – if you know where and how to look. Egypt is a great example. As global gas demand and infrastructure have grown, we've rewritten our strategy there. As well as extending the productivity of existing oil fields, BP teams are now applying new technology and capital to discover natural gas resources. In the Nile Delta, leading-edge aeromagnetic and seismic technology is allowing our exploration team to 'see' beneath the sea floor, taking them through deeper water towards uncharted gas reservoirs. The team's efforts in imaging, interpretation, integrated planning, testing and drilling have turned their raw data into real potential, and in 2004 confirmed the presence of a promising new gas field, called Raven. What's the next boundary? The team's newest wells will determine the Raven field's size. But they are already contributing towards BP's development of a major liquefied natural gas (LNG) business to help meet the world's growing demand for cleaner energy.

A mature outlook Conventional oil business wisdom holds that, once a field has reached maturity, its descent into unprofitability is almost inevitable. At BP, however, our people tend to see 'mature' fields differently. Since 2000, our existing profit centres have been run with an efficiency that's led to an average replacement rate of 72% for the proved reserves they have produced over this period. These 'mature' operations, some of which date back to the 1960s, have maintained their vitality. Today, their output is projected to decline at a modest 3% annually until 2008. What's made this possible? Discipline, creativity and the kind of operating efficiency that comes from decades of knowledge and innovative team practices in the field. We aim to extend this life expectancy. In established fields from Alaska to the North Sea, our teams are applying remote control and online field management, increasing well recovery rates, streamlining maintenance and even tapping into new discoveries. All of which means they're getting more from our existing hydrocarbon base with greater reliability and predictable cost – producing our resources as efficiently as we discover them.

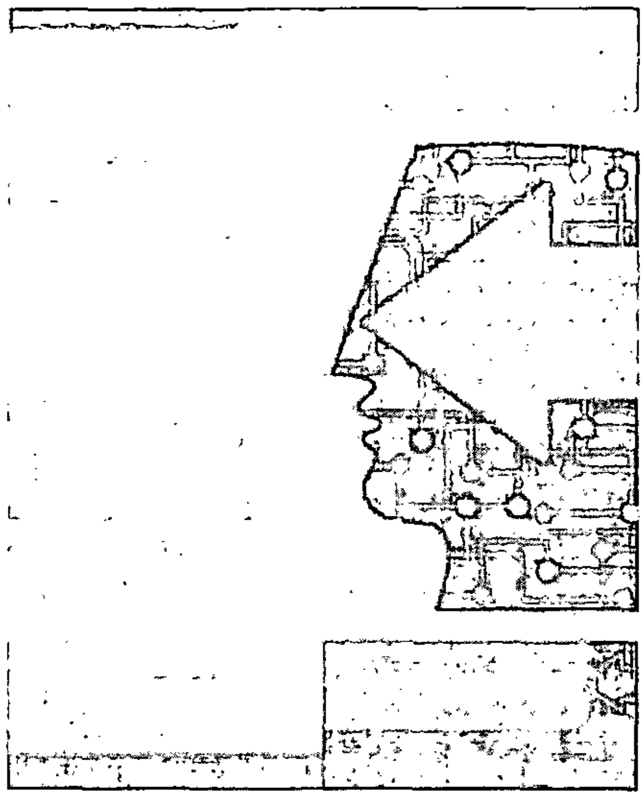
Producing in new dimensions How much? How long? What next? These are the biggest questions in the world of energy today. Part of the answer is a broader set of skills in production – creativity, efficiency, speed – to bring discoveries consistently and responsibly to market. In oil and gas fields worldwide, our people are helping to make us productive at an unprecedented scale. We now find oil and deliver new production with an efficiency that's on a par with the industry's best. *The ideas, energy and organization of our teams have also led us into our most prolific era for operational start-ups.* Over the last two years, we have completed nine major projects. From now until December 2006, we have 10 more major oil and gas project completions planned, including some of the world's largest construction projects in some of the most geologically challenging locations. Among them is the Gulf of Mexico, where our teams are redefining what is possible in deepwater operations at four fields simultaneously under development, including the massive Holstein platform *(above)*.

The best routes to market

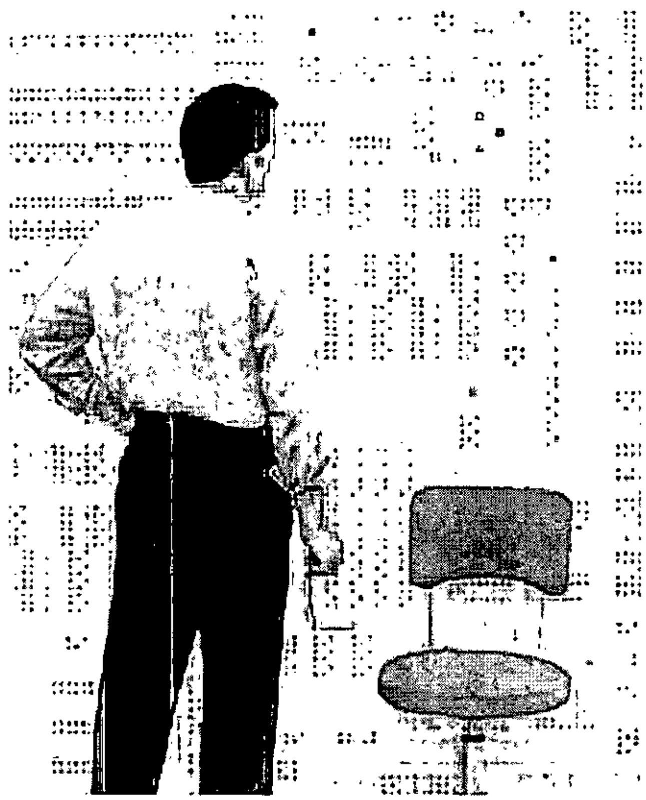
In today's energy marketplace, bringing resources to the world involves far more than making deliveries. It takes a business model that consistently finds the most efficient ways of getting there. After years of building assets in the natural gas marketplace, BP is now one of the world's largest non-state gas companies in terms of production and sales volumes. In the world's largest gas market, North America, we sell the largest volumes of end-user and wholesale gas, and are one of the largest marketers of natural gas liquids. Globally, in liquefied natural gas we are the second largest non-state supplier of gas into liquefaction plants. But our real advantage goes beyond our size and reach. It's the way our people run our businesses – the commercial and operational practices they use to open up markets for tomorrow and maximize the value of our resources today.



Building a mobile pipeline The distance between a natural gas field and a market can be measured in miles. It can also be calculated in years. BP's LNG strategy is bringing our gas closer to market. To capture a growing share of future customers for cleaner natural gas, our LNG teams have built a flexible system to supply growing demand – a 'mobile pipeline' to serve major regional markets and meet the needs of customers in the US, UK, Spain, Japan, South Korea and China. These locations increasingly rely on gas imports for primary energy and electricity needs, but they are often far from sources of natural gas. LNG bridges the gap: gas is lifted from underground, chilled to liquid, transported on ships from one part of the world to another, and then warmed back into gas to fuel a power plant, factory or home. As well as managing long-term point-to-point contracts, we are able to use our own ships to direct LNG to markets where demand is greatest and value highest – opening new markets and using the open seas to supply them.



Flowing with information In the marketplace for oil and gas, one of the most valuable commodities is intelligence – the ability to understand and interpret market information. You'll find our people at this intersection of supply and demand. Their minute-by-minute knowledge of the direction of supply and demand on a global basis is a discipline that allows our *teams to find the most productive links between assets and across supply chains. To streamline manufacturing flows.* And to serve our customers distinctively and with competitive advantage. We do this by making a significant investment in digital and communications technology. We align that investment with a host of 'people' capabilities – human strengths in analysis, logistics, trading and risk management. Our people use real-time data, information systems, transaction *automation and their own trading wisdom to act on some of the best available market intelligence worldwide. All this* allows BP to connect the dots in ways that others might not see, giving our customers a better level of service. That's how we take decisions that help to make the most of our resources.



Fine-tuning refining In refining, what matters more – processes or people? Traditional industry benchmarks for operational excellence in the refining business focus on uptime, the reliability of plant and equipment and the productivity of the manufacturing process. But people in our refining operations find that their individual actions – large and small – can help to set an even higher standard. Since 2002, our global refining workforce has started thinking of reliability in personal terms. By adopting the mindset of a High Reliability Organization (HRO), decision-making happens at the level where the knowledge and expertise reside. And this leads to faster, better decisions that drive consistent, high-quality operating performance and commercial production. More than a management technique, HRO is a way of thinking that encourages team members to speak out, find root causes of problems and take action early when they catch even the smallest failures. HRO is the way refining thinks best – and the best way we know to perform reliably for our customers.

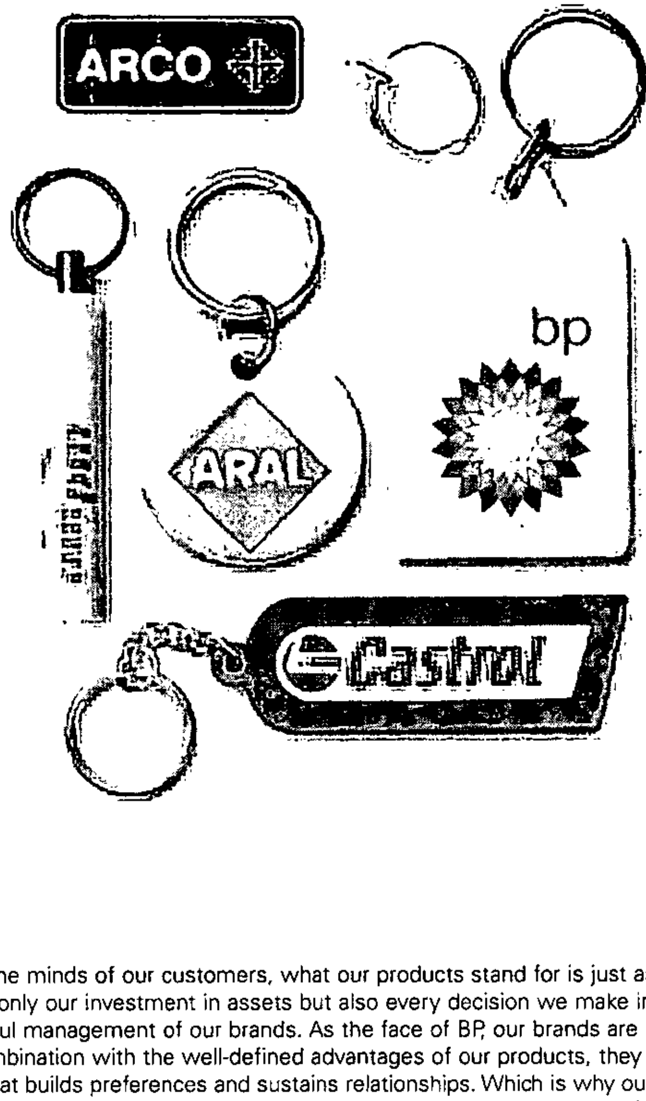
Getting closer to customers

Every day, in locations around the world, our people serve about 13 million customers. To put this in perspective, our businesses and brands – among them BP, Castrol, ARCO, Aral, Ultimate, Connect and am/pm – reach nearly as many customers as Wal-Mart, the world's largest retailer. But to be operationally excellent where our products meet the marketplace, our customer relationships have to be defined by quality as well as quantity – the distinctiveness and competitiveness of what we offer and the operating processes that underpin customer experiences. *Our customer-facing* businesses are gaining advantage and improving performance by carefully determining what customers want. By being consistent and creative in meeting those needs. By strengthening brands through innovation. And by locating facilities where they can most effectively and conveniently deliver our offers.

ARCO has the largest retail fuels market share on the US West Coast

Aral is the largest retail fuel marketer in Germany. Its position has benefited from the rebadging of the BP network, largely completed in 2004.

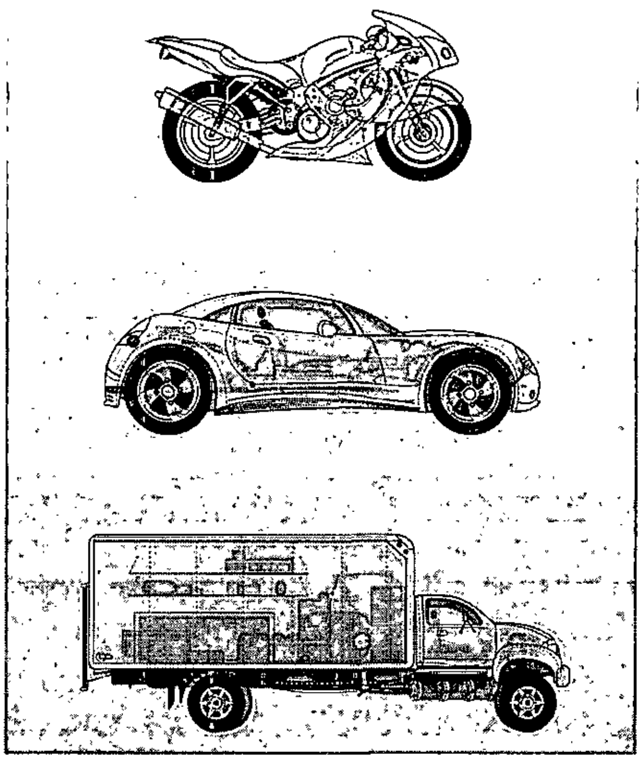
am/pm is the preferred fuel station convenience store brand on the US West Coast



The BP brand is strongly recognized throughout the world. Awareness of the brand is growing through improved business offers and targeted communication efforts

Castrol is one of the top-selling passenger car lubricants in the world.

Building a better brand In the minds of our customers, what our products stand for is just as important as what we make. This means that not only our investment in assets but also every decision we make in choosing routes to market must be sustained by careful management of our brands. As the face of BP, our brands are more than just logos. They are business assets. In combination with the well-defined advantages of our products, they tell a compelling story to our customers – the kind that builds preferences and sustains relationships. Which is why our brands rely on operational excellence. They include Ultimate, which is consistently ranked as the highest quality premium retail fuel by random samples of motorists. In lubricants, our Castrol brand has used its technological advantage, rigorous segmentation and customer loyalty to drive sales consistently ahead of market growth. Our updated and expanded retail locations are accelerating operating performance, increasing customers and driving sales per square metre. Applying operational excellence to the marketplace makes our brands more meaningful – and our businesses more valuable.

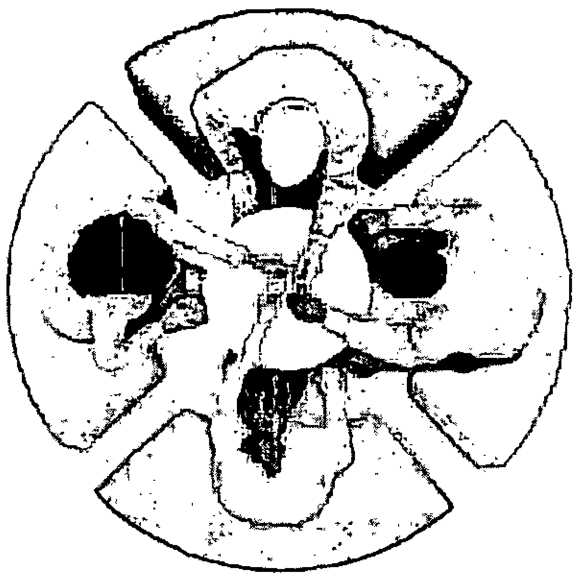


Driven by distinctiveness In striving for operational excellence, where you choose to compete is often as important as how efficiently you do it. BP's lubricants team has proved that effective strategic choices in market segmentation, customer relationships and brand visibility can enhance the value of assets and accelerate growth. In global lubricants markets, characterized by limited volume growth and increasing competitive pressure, BP stands out. Our marketing strength, technological distinctiveness and premium position have led to above-market year-on-year sales growth in automotive lubricants. What makes us different? While we sell lubricants, led by Castrol, in more than 100 countries worldwide, our people think in terms of market segments – motorcycles, passenger cars, trucks and vehicle manufacturers – rather than marketplaces. This perspective allows them to capture customers for whom our technology, consumer insight and brands add value and can generate higher returns for BP. In applying this strategy to new markets such as China, where lubricants growth is dramatic and preferences form quickly, our teams are already capitalizing on the strength of our brands to build distribution channels, market share and customer loyalty.

Solving the solar equation We all know the appeal of solar power – sustainability, acceptability and independence. Yet its potential as an energy source has often been overshadowed by its economics as a business. At least until now. Beginning in 2003, our BP solar team refocused its activities to become the profit centre that it could be – better understanding customers, operating at the right scale and reaching the best markets. We're now running a profitable solar operation – still small by BP standards, but one that grew its megawatt capacity sales of photovoltaic equipment by more than 30% in 2004. This performance is being driven by manufacturing consolidation, product innovation and, in particular, the team's focus on eight global sectors where well-defined customer needs, improved system performance and government incentives converge. A good example is Germany, the world's second largest solar market after Japan. Our large commercial installation at Geiseltalsee *(above)* provides sustainable benefits on two fronts: the field generates four megawatts of power, enough to supply 1,000 four-person households each year, and has reclaimed the site of a former oil depot.

The point of excellence

Our upstream and downstream activities reach not only the marketplace but also investors, regulators, government leaders and the public. Our abilities as an organization to sustain and improve our standing among these groups are key to our definition of operational excellence. These abilities support our new scope and scale while retaining the diverse heritage of our people and businesses. They help equip BP with the skills, knowledge and reputation that enable us to conduct business in a chosen country – and let us navigate an increasingly complex and unpredictable world with sensitivity.



Our human potential In business in general, and within BP in particular, the relationship between employee and performance is unbreakable. Simply put, our employees hold the knowledge, skills and energy that enable our enterprise to thrive. At BP, operational excellence includes the ways in which we expand our employees' range of possibilities as they expand ours. A good example is our Projects Academy. In 2003, we began working with the Massachusetts Institute of Technology (MIT) to change how our teams deliver major projects. Focusing on project leadership, business knowledge and technical excellence, the MIT programme is bringing BP's senior project leaders together with recognized leaders in engineering and project management. The first two Projects Academy classes graduated in 2004. Their members are already applying new insights to manage the complexity of their projects, understand team dynamics, clarify priorities and build a well-connected network of ideas. The Projects Academy, Marketing Academy and other practical initiatives give BP the capacity to learn and share knowledge on an everyday, global basis, and to grow our most prized resource – our people.

Financial performance

Business environment
Trading conditions in 2004 were affected by tight supplies in oil markets and by strong world economic growth.

Average crude oil prices in nominal terms in 2004 were the highest for 20 years, driven by exceptionally strong global oil demand growth and the physical disruption to US oil operations caused by Hurricane Ivan. The Brent price averaged $38.27 per barrel, an increase of more than $9 per barrel over the $28.83 per barrel average seen in 2003, and varied between $29.13 and $52.03 per barrel.

Natural gas prices in the US were also strong during 2004. The Henry Hub First of the Month Index averaged $6.13 per million British thermal units (mmBtu), up by more than $0.70 per mmBtu compared with the 2003 average of $5.37 per mmBtu. Prices fell slightly relative to oil prices as the levels of gas in storage rose sharply. UK gas prices were also up strongly in 2004, averaging 24.39 pence per therm at the National Balancing Point compared with a 2003 average of 20.28 pence per therm.

Refining margins averaged record highs in 2004, despite weakening towards the end of the year. This reflected strong oil demand growth and record refinery throughput levels. Retail margins weakened in 2004, as rising product prices and price volatility made their impact in a competitive marketplace.

In Petrochemicals, generally improved market conditions led to a gradual increase in both volumes and margins through the year. Such gains were, however, partially offset by high and volatile energy and feedstock prices, together with adverse foreign exchange impacts.

Results
BP's result for the year was $16,208 million, compared with $12,858 million in 2003. The result per share was 74.27 cents, an increase of 28%. Replacement cost profit was $14,088 million (2003 $10,466 million). Both the result and replacement cost profit include exceptional and non-operating items.

The return on average capital employed was 20%, compared with 18% in 2003. On a replacement cost basis, the 2004 return was 15% (2003 12%), and 17% (2003 12%) on a historical cost basis.

Net exceptional gains of $815 million before tax principally relate to gains from the sale of our interests in PetroChina and Sinopec and the divestment of certain upstream interests, partly offset by net losses on a number of business sales and facility closures.

Non-operating items in 2004 were a net charge of $2,120 million before tax and are shown on page 25. The majority of the asset write-downs and impairments relate to the Petrochemicals segment, reflecting the portfolio separation described on page 28.

Interest expense was $642 million, compared with $644 million in 2003. This primarily reflects lower interest rates and debt buyback costs and an increase in capitalized interest, offset by the inclusion of BP's share of a full year's interest expense from TNK-BP in 2004.

Corporate tax expense was $8,282 million (2003 $6,111 million), representing an effective tax rate of 34% on the pro forma result (2003 32%).

Historical cost profit was $15,731 million, including exceptional net gains after tax of $1,076 million and stock holding gains of $1,643 million. The corresponding figures for 2003 were $10,482 million profit, $708 million net gains and $16 million gains respectively.

Capital expenditure and acquisitions amounted to $17,249 million, including $1,354 million for including TNK's interest in Slavneft within TNK-BP and $1,355 million for the acquisition of Solvay's interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America. Excluding acquisitions, capital expenditure was $14,408 million, compared with $13,986 million in 2003.

Net cash inflow for the year was $6,038 million, compared with an inflow of $1,405 million in 2003; higher operating cash

Reconciliation of reported profit/loss to pro forma result

						$ million
			2004			2003
	Reported[a]	Acquisition amortization[b]	Pro forma result	Reported[a]	Acquisition amortization[b]	Pro forma result
Exploration and Production	18,520	1,239	19,759	14,666	1,566	16,232
Refining and Marketing	4,722	881	5,603	2,318	826	3,144
Petrochemicals	(900)	–	(900)	568	–	568
Gas, Power and Renewables	943	–	943	570	–	570
Other businesses and corporate	314	–	314	(184)	–	(184)
Replacement cost profit before interest and tax	23,599	2,120	25,719	17,938	2,392	20,330
Interest and other finance expense	(999)	–	(999)	(1,191)	–	(1,191)
Taxation	(8,282)	–	(8,282)	(6,111)	–	(6,111)
Minority shareholders' interest (MSI)	(230)	–	(230)	(170)	–	(170)
Replacement cost profit	14,088	2,120	16,208	10,466	2,392	12,858
Stock holding gains (losses), net of MSI	1,643			16		
Historical cost profit	15,731			10,482		

[a] Replacement cost profit for the period includes the net profit or loss on the sale of fixed assets and businesses or termination of operations. It also includes non-operating items identified by the group, primarily asset write-downs/impairment, environmental and other provisions and restructuring, integration and rationalization costs. These items do not meet the criteria to be classified as operating exceptional items.
[b] Acquisition amortization refers to depreciation relating to the fixed asset revaluation adjustment and amortization of goodwill consequent upon the ARCO and Burmah Castrol acquisitions. The results for 2003 and 2004 include accelerated depreciation of the revaluation adjustment in respect of the impairment of former ARCO assets of $381 million and $214 million, respectively.

flow and higher dividends from joint ventures were partly offset by higher tax payments, lower disposal proceeds and higher acquisition spending. Net cash outflow for capital expenditure and acquisitions, net of disposals, was $11,954 million (2003 $9,672 million). During 2004, we made incremental payments of $395 million into a number of the group's pension funds (2003 $2,533 million).

The group's net debt, that is debt less cash and liquid resources, was $21,607 million at the end of 2004, compared with $20,193 million at the end of the previous year. The ratio of net debt to net debt plus equity was 24%, at the bottom of the target range, compared with 26% a year ago. On a reported basis, the percentage was 22% (2003 22%).

In addition to reported debt, BP uses conventional off balance sheet sources of finance such as operating leases and borrowings in joint ventures and associates. The group has access to significant sources of liquidity in the form of committed facilities and other arrangements.

Dividends and share repurchases

The total dividends announced for 2004 were $6,371 million, against $5,753 million in 2003. Dividends per share for 2004 were 29.45 cents, an increase of 13% compared with 2003. In sterling terms, the dividend was 4% higher. This increase is a result of our strong cash flow and improvements in underlying performance in line with strategy. In addition, our confidence in the future enabled us to make a step change in the fourth quarterly dividend. The board sets the dividend based upon the prevailing circumstances of the group, future investment patterns and the sustainability of the group, and the future trading environment. The steady increases in the dollar dividend in recent years reflect the board's progressive dividend policy.

BP intends to continue the operation of the Dividend Reinvestment Plan (DRIP) for shareholders who wish to receive their dividend in the form of shares rather than cash. The BP Direct Access Plan for US and Canadian investors also includes a dividend reinvestment feature.

The group aims to demonstrate financial discipline by balancing cash in and cash out over time. When trading conditions are favourable, cash flow may be in excess of what is needed for operational requirements, including funding the capital programme and any acquisitions and dividend payments. As part of giving a return to shareholders, one of the steps we take from time to time is to repurchase our own shares. During 2004, a total of 827 million shares were repurchased and cancelled at a cost of $7,548 million. The repurchased shares had a nominal value of $207 million and represented 3.7% of ordinary shares in issue at the end of 2003. Since the inception of the share repurchase programme in 2000, 1,602 million shares have been repurchased and cancelled at a cost of $13.5 billion. BP intends to continue making share repurchases, subject to market conditions and continuing authority at the April 2005 annual general meeting.

During the year, shares to the value of $1.25 billion were issued to Alfa Group and Access-Renova (AAR) as the first instalment of the deferred consideration for our investment in TNK-BP. Two more instalments of $1.25 billion are due in the third quarters of 2005 and 2006.

External environment

	2004	2003
BP average liquids realizations ($/barrel)	35.39	27.25
Brent oil price ($/barrel)	38.27	28.83
BP average natural gas realizations ($/thousand cubic feet)	3.86	3.39
Henry Hub gas price ($/mmBtu)	6.13	5.37
Global indicator refining margin ($/barrel)	6.08	3.88
Chemicals indicator margin ($/tonne)	140[a]	112

[a]Provisional.

Operating statistics

	2004	2003
Liquids production (thousand b/d)	2,531	2,121
Gas production (million cf/d)	8,503	8,613
Total production (thousand boe/d)	3,997	3,606
Refinery throughputs (thousand b/d)	2,976	3,097
Marketing sales (thousand b/d)	4,002	3,969
Petrochemicals production (thousand tonnes)	28,927	27,943
Gas sales (million cf/d)	31,690	30,439

Non-operating items $ million

	2004	2003
Asset write-downs/impairment	1,529	357
Environmental and other provisions	489	582
Restructuring, integration and rationalization costs	141	399
Other	(39)	(559)
Total non-operating items before tax	2,120	779
Taxation[a]	(559)	(551)
Total non-operating items after tax	1,561	228

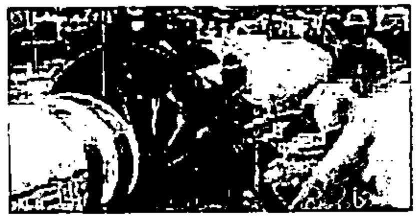
[a]2003 includes tax restructuring benefits.

Capital investment $ million

	2004	2003
Exploration and Production	9,839	9,658
Refining and Marketing	2,887	3,006
Petrochemicals	929	775
Gas, Power and Renewables	538	359
Other businesses and corporate	215	188
Capital expenditure	14,408	13,986
Acquisitions	2,841	6,026
	17,249	20,012
Disposals	(5,048)	(6,432)
Net investment	12,201	13,580

Business performance

Exploration and Production



Segment results ($ million)

Strategy

- Create new profit centres by accessing areas with the potential for large oil and natural gas fields; exploring successfully; and pursuing the best projects for development.
- Manage the performance of producing assets by investing in the best available opportunities and optimizing operating efficiency.
- Sell assets that are no longer strategic to us and have greater value to others.

Focus

BP invests in a portfolio of large, lower-cost oil and natural gas fields chosen for their potentially strong return on capital employed, and seeks to manage those assets safely with maximum capital and operating efficiency. We continue to develop new profit centres in which we have a distinctive position: Trinidad, Angola, Azerbaijan, deepwater Gulf of Mexico, Asia Pacific gas and Algeria. These new profit centres, in addition to our growing operations in Russia, augment the production assets in our existing profit centres, providing greater reach, investment choice and opportunity for growth.

Exploration and Production

The result for the year was a record $19,759 million, representing an improvement of 22% over 2003, arising from increased production and higher oil and gas prices.

Our production was 3,997 thousand barrels of oil equivalent per day, an increase of more than 10% over 2003, primarily from incremental production in TNK-BP and our new profit centres. The increase was partly offset by a severe hurricane season in the Gulf of Mexico, a blow-out at the non-BP-operated Temsah platform in Egypt, the impact of divestments and decline in our existing profit centres.

We sanctioned four new major projects (Azeri-Chirag-Gunashli phase three in Azerbaijan, Rosa in Angola, Magnus extension in the UK North Sea and viscous oil in Alaska) and completed four major projects (In Salah in Algeria, Australia North West Shelf Train 4, Kizomba A in Angola and Holstein in the Gulf of Mexico). The increase in capital spending this year primarily reflected continued high development activity as we progressed projects in the new profit centres. Despite significant success across the supply chain to minimize the impact, inflationary pressures on our raw materials and the weaker dollar contributed to the increase.

Progress continued in our existing profit centres. Production from the Cerro Dragon field in Argentina grew through further infill drilling. In the North Sea, progress continued as expected on the Rhum development.

Each of our new profit centres progressed in line with our expectations this year.

In Trinidad, from where BP has prime access to US and European liquefied natural gas (LNG) markets, we built on our integrated position. In July, Atlas Methanol, the world's largest methanol plant, came on line. Train 4 of Atlantic LNG remains on track for start-up in the fourth quarter of 2005. It will be supplied in part by the Cannonball gas development, which is Trinidad and Tobago's first major in-country offshore construction project.

In Azerbaijan, construction continued on the Central Azeri field, with topsides commissioning under way. First oil is expected in the first half of 2005. We plan to transport this oil via the 1,760-kilometre Baku-Tbilisi-Ceyhan (BTC) pipeline. When complete, the pipeline will export crude oil from the Caspian to world markets. In addition, construction continued on the Shah Deniz gas field, and in-country assembly of the drilling rig and platform is under way for a planned 2006 start-up.

In the Gulf of Mexico, the Holstein field started production in December, despite the effects of Hurricane Ivan. In 2004, significant progress was made on Mad Dog, currently in the final commissioning stages with first production expected in early 2005, and on Thunder Horse, on track to begin production by the end of 2005. This will be followed by Atlantis, with first production expected in 2006.

In Angola, the Kizomba A field started production in August, ahead of schedule, while Kizomba B remains on track for start-up in late 2005. All major contracts were awarded on the Greater Plutonio development and fabrication of the Floating Production Storage and Offloading topsides began.

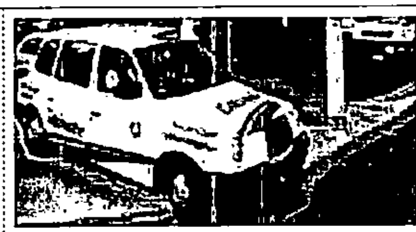
In Algeria, the In Salah project started production in mid-2004 and the In Amenas project remains on track for start-up in late 2005-early 2006.

Oil production from TNK-BP (excluding Slavneft) grew by about 14% over 2003. Our result for the year included $2.4 billion from TNK-BP. We also received $1.9 billion of cash dividends from the venture.

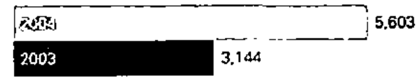
We continually seek to enhance our portfolio through a planned annual divestment programme.

In 2004, this yielded $747 million of proceeds and covered assets primarily in Indonesia, the US and Canada. We also signed sales and purchase agreements for the Ormen

Refining and Marketing



Segment results ($ million)



Strategy

- Focus on refining locations where scale, configuration and operational excellence earn distinctive returns.
- Focus on retail fuel and convenience markets where supply advantage and distinctive offer can capture market share.
- Leverage our brand and technology with a key focus on automotive-related lubricants markets.
- Build strong strategic relationships in the business-to-business sector.
- Enhance our existing strength in selected emerging markets, particularly China.

Focus

Our marketing businesses, underpinned by world-class manufacturing, generate customer value by providing quality products and offers. Our retail, lubricants and business-to-business sectors reach about 13 million customers a day. Our retail strategy provides differentiated fuel and convenience offers to some of the most attractive global markets. Our lubricants brands offer customers benefits through technology and relationships. We have deep business-to-business customer relationships and strategic partnerships. We seek to improve the quality of our manufacturing portfolio and our products.

Lange field in Norway, which is planned to complete in early 2005.

New oil and gas discoveries were made in Egypt, Angola, the deepwater Gulf of Mexico, Trinidad and offshore Sakhalin Island in Russia. Recoverable oil and gas from these finds is estimated to be more than one billion barrels of oil equivalent.

On the basis of UK generally accepted accounting practice (SORP), our proved reserves replacement ratio (RRR) was 106%, excluding equity-accounted entities. On the same basis, including equity-accounted entities, the RRR was 110%. This was the 12th consecutive year in which our RRR was greater than 100%. We also prepare estimates of our proved reserves on the basis of the rules and interpretation required by the US Securities and Exchange Commission (SEC). On this basis, our RRR was 78%, excluding equity-accounted entities, and 89%, including equity-accounted entities. The differences from our SORP-based estimates arise mainly from the use of year-end pricing, as required by the SEC. All our proved reserves replacement ratios are based on discoveries, extensions, revisions and improved recovery and exclude the effects of acquisitions and disposals. BP has a robust internal process to control the quality of its reserve bookings, which forms part of a holistic and integrated system of internal control. Details of that process and the applicable rules are described on pages 87-88.

Refining and Marketing

Strong refining margins, combined with robust operating performance, led to a result of $5,603 million in 2004, a 78% improvement from 2003. The relative weakening of the US dollar compared with the euro and sterling negatively affected results.

In our marketing businesses, strongly competitive sales growth was maintained. This resulted both from our investment to increase the quality of our portfolio and from our focus on operational excellence. Owing to increased crude product and base oil prices, margins overall declined slightly against those of 2003. We continued to strengthen our competitive position in all our operations through improved site operating models and the development of distinctive offers for customers.

Our investment in China deepened through two new joint ventures with PetroChina and Sinopec. We continued to review our portfolio, resulting in the disposal of our refining, retail and liquefied petroleum gas (LPG) businesses in Singapore, while further retail network asset disposals were completed in 2004. From 1 January 2005, the Aromatics and Acetyls businesses will join the segment and the Lavéra and Grangemouth refineries will be included in the Olefins and Derivatives business.

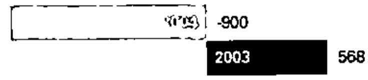
A record performance for the refining business was underpinned by strong product demand and good availability, which averaged 95.4% in 2004. We concentrated on optimizing our assets and taking advantage of our global scale and presence. Focus on supply optimization, feedstock selection and product value maximization helped us to capture high margins. BP's Global Indicator Refining Margin was $6.08 a barrel, up from $3.88 in 2003. Total global refining throughput was down by about 4% as a result of planned disposals.

In our retail business, the number of sites carrying the BP helios expanded to 19,828 worldwide during 2004. We launched Ultimate gasoline and diesel fuels in Australia, Austria, France, Germany, Poland and Portugal. These enhanced products deliver improved performance with fewer emissions than standard fuel grades, and have received positive responses from customers.

In our lubricants business, we focused on pursuing key

Petrochemicals

Segment results ($ million)



Strategy

- Separate the portfolio, enabling the individual parts to develop strategic paths that deliver distinctive returns. We plan to divest the Olefins and Derivatives business, possibly starting with an Initial Public Offering in the second half of 2005, subject to market conditions and necessary approvals.
- Integrate the Aromatics and Acetyls businesses within the Refining and Marketing segment, gaining operational and organizational synergies. Maintain leading market shares and technology in these high-growth businesses, with a strong presence in Asia.
- Focus the overall portfolio on areas with competitive advantage and restructure other assets.

Focus

Our petrochemicals businesses have significant global market positions, underpinned by leading proprietary technology and strong manufacturing capabilities. Our activities focus on those areas with a distinctive and significant competitive position. Our products are ultimately used to service a wide range of consumer applications, increasingly in the fast-growing markets of Asia Pacific and China in particular.

customer segments and markets where we believe we have a premium position. Our brands continued to experience above-market volume growth, supported by new marketing initiatives. Growth was particularly strong in Asia, with Castrol BikeZone successfully launched in India and Vietnam. New product launches took place across the world, including Castrol GTX Start Up in the US and Castrol GTX High Mileage in Europe.

2004 was also a good year for business-to-business fuels marketing activity in both margin and volume, particularly in the marine and aviation sectors. This was partially offset by margin squeeze and price lag in the lubricants and LPG businesses, although volume demand remained robust. We also successfully launched the innovative new BP Gaslight composite LPG cylinder and Castrol TLX Plus in marine lubricants.

Petrochemicals

Petrochemicals' result was a loss of $900 million in 2004. Record sales and production volumes, underpinned by strong demand and by increased utilization and reliability at manufacturing sites, were more than offset by higher exceptional and non-operating charges.

Focus on commercial and operational excellence, together with generally improved market conditions, accelerated performance. Margin expansion was achieved despite high and volatile prices for energy and feedstocks.

The segment continued to upgrade its portfolio, focusing on areas with competitive advantage. As a consequence, several businesses that did not meet our strategic and financial criteria were sold, together with the announced closure of several manufacturing units. Substantial progress was made in constructing the SECCO chemicals complex near Shanghai (BP 50%) and expanding the Chocolate Bayou olefins operation in Texas. Output from these investments is expected in 2005.

In 2004, we announced that, from 1 January 2005, the Olefins and Derivatives (O&D) business would operate on a standalone basis within the BP group. We plan to divest the O&D business, possibly starting with an Initial Public Offering in the second half of 2005, subject to market conditions and the receipt of necessary approvals. The O&D business markets a wide range of petrochemicals, manufactured in more than 20 locations worldwide.

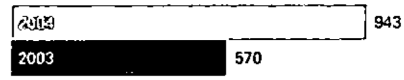
During 2004, several initiatives were announced, designed to strengthen the competitive standing of the O&D business. The Grangemouth and Lavéra refineries will be incorporated into O&D, so preserving the opportunity to enhance further the benefits of site integration with their neighbouring petrochemicals operations. BP also agreed to acquire Solvay's interests in the two BP Solvay high-density polyethylene ventures for inclusion in O&D. Finally, Nova Chemicals and O&D agreed in principle to combine their respective styrene polymer interests in a joint venture, creating a major European polystyrene operation. Subject to regulatory approval, the joint venture is expected to start in mid-2005.

BP will retain the Aromatics and Acetyls (A&A) operations as an important part of its customer-facing activities. The A&A businesses have among the largest global market shares and advanced technologies in these high-growth sectors. BP aims to grow the A&A businesses and several ongoing expansion projects in Asia will start up in 2005.

With the announced changes, the Petrochemicals segment ceased to report separately as from 1 January 2005. The A&A operations will be included within the Refining and Marketing segment; the O&D business will report within Other businesses and corporate. The new structure is designed to offer the greatest opportunity for further improvement in overall performance and financial returns.

Gas, Power and Renewables

Segment results ($ million)



Strategy

- Capture distinctive world-scale market positions ahead of supply.
- Expand gross margin by providing distinctive products to selected customer segments and optimizing the gas and power value chains.
- Build a sustainable solar business and continue to assess the application of renewable and alternative energy sources.

Focus

In line with changing demand patterns for cleaner fuels, BP seeks to participate at scale in the fast-growing markets for natural gas, gas liquids and solar energy. We currently hold some of the largest market shares in volumes sold in North American gas and natural gas liquids (NGLs) and significant strength in both the liquefied natural gas (LNG) and solar global markets. We are expanding our LNG business by accessing import terminals in Asia Pacific, North America and Europe.

Gas, Power and Renewables

The result for the year was $943 million, an increase of 65% over 2003 and underpinned by record sales volumes achieved across all four principal business areas of LNG, NGLs, gas marketing and solar. The NGLs business benefited from a firm market environment by increasing sales by 14% and achieving high levels of availability. Sales of natural gas increased by 4%, while volumes of gas supplied into liquefaction plants rose by 11%. The solar business grew sales by 38% and delivered a full-year operating profit for the first time.

We took a number of important steps to access major growth markets for the group's equity gas. In Asia Pacific, agreements for the supply of LNG from the proposed Tangguh development in Indonesia (BP 37.16%) were signed with POSCO and K Power for supply to South Korea and with Sempra for supply to Mexico and US markets. Together with an earlier agreement to supply LNG to China, more than seven million tonnes a year of Tangguh LNG have been secured. This was a significant factor in the decision to sanction the development in early 2005.

In the Atlantic and Mediterranean regions, significant progress was also made in creating opportunities to supply LNG to North American and European gas markets. In Egypt, we signed agreements to supply gas to the Damietta LNG plant and to purchase 1.45 billion cubic metres per year of LNG for supply to world markets. Agreements finalized with NGT Transco will make BP and Sonatrach of Algeria the first companies since the 1980s to import LNG into the UK market from 2005.

Plans for the development of new LNG import terminals on the US East and Gulf coasts made good progress. These new access points to market, together with existing capacity rights at Cove Point in Maryland, US, Bilbao in Spain and Isle of Grain, UK, should provide important opportunities to maximize the value of the group's gas supplies from Trinidad, Egypt and elsewhere.

In the NGLs business, we maintained our position in North America as one of the largest marketers and producers in terms of production and sales volumes. There we had a very strong year, benefiting from the high prices of NGLs seen during 2004 and the wide differences between natural gas feedstocks and liquids prices, which give higher earnings. In Egypt, a new NGLs extraction plant (BP 33.33%) began gas processing at Port Said.

Our gas marketing and trading business had a good year, with an operating result ahead of 2003's record performance. In North America, we are the largest gas marketer in volumes sold to end-use and wholesale markets and have a growing power marketing and trading business. Our marketing and trading scale and scope provide exemplary market access for the group's North American equity gas production and LNG imports. We secured long-term capacity in several new western US pipeline projects to support expected Rockies production growth and avoid capacity constraints seen in the past. We continued to expand our market presence in North America by acquiring two gas marketing companies and extending two key energy alliance agreements.

Our solar business saw a record year, with strong sales growth, a positive operating result and positive cash flow. The business benefited from the restructuring undertaken in 2003, which reduced the cost of supply, and also from strong industry demand, which is supporting higher revenues. We reduced product lines and distributors and improved customer focus and brand loyalty. Our global 'lean manufacturing' initiative delivered major improvements in productivity, and production from our main operating facilities in Madrid, Spain, and Frederick, US, was stepped up to supply the higher sales.

Environmental and social performance

Our fundamental purpose, as defined by BP's board, is to maximize shareholder value on a long-term basis by providing constantly improving goods and services in a strongly competitive way. To be sustainably successful, we have to gain and retain the support of many people, including employees, shareholders, customers and communities. This report summarizes our performance. More detail is published in *BP Sustainability Report 2004*.

BP: our business

The way we work is guided by values – integrity, honest dealing, treating everyone with respect and dignity, striving for mutual advantage, transparency and contributing to human progress. These values are enshrined in practical policies and standards that govern areas of our activity, including health, safety, security, environment, ethical conduct and business relationships.

We use a system of risk management to assess the impact of our activities on the environment, local economies and communities. Where appropriate, accountability for managing environmental and social impacts is part of managers' performance contracts, with specific objectives and milestones.

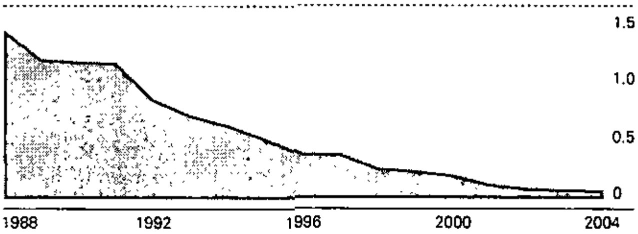
People's safety is of the highest priority. Managers are accountable for ensuring that safety risks are properly addressed, staff are trained and facilities are well maintained. We closely monitor our safety performance.

In 2004, the number of injury cases (resulting in our employees or contractors being away from work for a day or more) was 0.08 per 200,000 hours worked, compared with 0.09 in 2003. This performance is approaching the best in our industry and also within our target set at 0.09 for 2004.

Despite meeting this important target and reducing overall injury rates, we deeply regret the 11 workforce fatalities in 2004. This compares with 20 in 2003 and 13 in 2002.

As a global organization, we believe our workforce, leadership and recruitment should reflect the diverse communities in which we operate. We are continuing to focus on employing and developing local staff and leaders in our operations worldwide. Programmes in countries including China, Angola and Azerbaijan are ensuring that we continue to increase the number of local employees.

Long-term improvement in safety performance (DAFWCF)[a] 1988-2004



[a] Days away from work case frequency (DAFWCF) is the annual frequency (per 200,000 hours) of injuries that result in a person (employee or contractor) being unable to work for a day (shift) or more. For a full understanding of the underlying data on DAFWCF, please refer to our website.

Our policy is to ensure equal opportunity in recruitment, career development, promotion, training and reward for all employees, including those with disabilities. All applicants and employees are assessed against clear criteria related to job requirements. Where existing employees become disabled, our policy is to provide continuing employment and training wherever practicable.

Our People Assurance Survey (PAS), completed by 74% of our employees in 2004, showed a 4% improvement in overall employee satisfaction.

BP values the diversity of its leadership. At the end of 2004, 15% of our top 610 leaders were female and 19% were of nationalities other than the UK or US. Our employee surveys show that an inclusive culture is spreading. In 2004, 70% of BP employees who responded to the PAS believed the company had created an environment where people with diverse backgrounds could succeed, up from 67% in 2003 and 60% in 2000. We strive to build an environment in which everyone can feel part of a meritocratic organization.

During 2004, we made further progress in learning and development opportunities for employees. Around 5,000 people undertook the First Level Leaders programme, which provides training for the first tier of management. More than 1,800 of our 6,000 senior leaders took part in the Senior Level Leaders programme, designed to develop their leadership capabilities.

BP's fourth Global Graduate Forum was attended by around 300 graduates who joined in 2002, while around 250 people attended the Discover BP programme, launched to help senior experienced recruits integrate rapidly into BP.

We continue to support employee share ownership. Through our award-winning ShareMatch plan, run in 75 countries, we match BP shares purchased by employees.

Communications with employees include global and local magazines, intranet sites, DVDs, targeted e-mails and face-to-face communication. Team meetings are the core of our employee consultation, complemented by formal processes through works councils in parts of Europe. This communication, along with training programmes, raises awareness of the financial, economic, social and environmental factors affecting BP's performance and contributes to employee development and motivation.

We continue to emphasize the importance of doing business with high standards of ethical conduct. To enhance our focus on compliance with laws, regulations and internal policies and standards, we developed a new centralized compliance and ethics function during 2004.

We promote our global employee concerns programme – OpenTalk – to give our staff the opportunity to report possible breaches of law or company policy without fear of retaliation. OpenTalk can be contacted via telephone, letter, e-mail or fax and provides a translation service. Matters raised are held in strict confidence and are referred for investigation via regional ombudsmen within BP for resolution. During 2004, 343 reports were received from 44 countries and, where appropriate, action was taken.

Staff in positions of responsibility review with their teams all compliance and ethical issues arising during the year. They then certify to their manager that their personal actions and those of their teams have complied with the law and with company policy, disclosing any areas of possible non-compliance. On completion of the process, the group chief executive prepares his personal certificate on behalf of BP. In future years, these reports will be prepared against the requirements outlined in our new code of conduct.

We continue to apply our strong anti-corruption policy, including prohibiting facilitation payments and identifying and correcting any areas of non-compliance. We take disciplinary measures where appropriate. In 2004, this included the dismissal of 252 people for unethical behaviour, including fraud, theft and dishonesty.

BP does not make corporate political contributions anywhere in the world and specifically made no donations to UK or other EU political parties or organizations in 2004.

Promoting health awareness among our employees, contractors and local communities provides long-term benefits to our people and our business. In many areas of the world we face significant health issues, such as HIV/AIDS. During 2004, we increased our capability to assess health risks and implemented local initiatives.

BP and the environment

BP was the first major oil company to state publicly that the risks of climate change were serious and that precautionary action was justified. While uncertainties remain, we believe business planning and long-term strategy should be based on the need to stabilize atmospheric concentrations of greenhouse gases.

In 2001, BP had succeeded in lowering operational emissions by 10% from 1990 levels. We now aim to offset growth in our emissions by 2012, with reductions achieved partly from operational efficiency projects and partly from the supply of products that are cleaner or offer improved fuel efficiency.

Our 2004 operational emissions of 81.7 million tonnes (Mte) were similar to those of 2003 (83.4Mte). Our emissions would have been higher but for planned improvements in operational efficiencies and divestments. The efficiencies resulted in more than 1Mte of sustainable reductions, which now total about 4Mte since 2001.

BP recognizes the need to protect and conserve sensitive areas that house the rich biodiversity of our planet. We will only work within sensitive areas if we believe we can properly manage any risks to the environment.

We have made a commitment to publish the results of risk assessments relating to any new activities in World Conservation Union (IUCN) designated sites. In 2004, no decisions were taken to go into such areas. Our website details all known IUCN category I to VI areas where we have facilities. During 2004, further work was undertaken to ensure that our approach when entering areas for exploration and production is consistent and transparent.

By the end of 2004, 100% of our major operations had been independently certified to the ISO 14001 international standard on environmental management. This system drives continuous performance improvement at our sites to reduce air emissions, water discharges and accidental releases, including oil spills to sea or land.

Our shipping fleet transports significant volumes of oil and gas around the world. In 2004, BP continued its strategy of increasing its fleet in order to control the risk of a major oil spill more effectively. Our owned and operated fleet has grown from 36 ships in 2003 to 42 ships in December 2004, 38 of which are double-hulled. Most of these vessels are leased, an approach that enables the group to renew the fleet periodically. We also charter additional vessels, which are vetted to ensure they meet our rigorous standards.

In the area of renewable and alternative energies, BP's research and development focus has been on photovoltaics and hydrogen. We are pursuing initiatives aimed at improving the efficiency and cost of solar cells as well as the development of new silicon sources and alternative wafer fabrication techniques. In hydrogen, we use our international portfolio of practical demonstration projects to test new technologies and foster innovation.

BP in society

We try to ensure that our relationships with non-governmental organizations (NGOs), customers, suppliers, communities and governments are founded on the basis of mutual advantage. Our relationships develop over many years by seeking to understand the needs and aspirations of all with whom we do business.

We made further progress on some concerns related to the construction of the BTC pipeline, a project that has attracted some NGO opposition, particularly over human rights issues. The pipeline is being constructed to transport oil from the Caspian to the Mediterranean, so avoiding shipping through the Bosporus, and will help meet growing world demand.

We believe that open and thriving societies create the best environment for business. During 2004, we contributed to international discussions on the issue of transparency. The Extractive Industries Transparency Initiative (EITI) is an important programme that provides guidelines for disclosing the amount of revenue governments receive from energy companies, so demonstrating the scale of the funds available for public spending. Towards the end of 2004, a Memorandum of Understanding was signed in Baku, Azerbaijan, by the government, state and foreign oil companies, setting out clearly the process for implementation of the EITI in Azerbaijan. BP is committed to encouraging the acceleration of this process and will be supporting it with the publication of relevant data and information.

Our business activities affect – and benefit – people worldwide. We seek to extend these benefits as broadly as possible. During 2004, we reviewed our strategy of social investment and intend to focus on education, on the development of thriving local enterprise and on providing access to energy in remote locations. We continue to support many initiatives in the communities in which we operate.

Other financial issues

Critical accounting policies

BP prepares its financial statements in accordance with UK generally accepted accounting practice (UK GAAP). The group's significant accounting policies are summarized on pages 40-43.

The accounts for the year ended 31 December 2004 have been prepared using accounting policies consistent with those adopted in the preparation of the 2003 accounts, except for the change in accounting policy for pensions and other post-retirement benefits and for shares held in employee share ownership plans for the benefit of employee share schemes.

Segment information for 2003 has been restated to reflect the transfer of the natural gas liquids (NGLs) activities from Exploration and Production to Gas, Power and Renewables.

Inherent in the application of many of the accounting policies used in the preparation of the financial statements is the need for BP management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from the estimates and assumptions used.

The following summary provides further information about the critical accounting policies that could have a significant impact on the results of the group and should be read in conjunction with the Notes on Accounts.

The accounting policies and areas that require the most significant judgements and estimates to be used in the preparation of the consolidated financial statements are in relation to oil and natural gas accounting, including the estimation of reserves; impairment; and provisions for deferred taxation, decommissioning, environmental liabilities, pensions and other post-retirement benefits.

Accounting policy changes in 2004

From 1 January 2004, BP changed its accounting policies for pensions and other post-retirement benefits. In addition, BP also changed its accounting policy for shares held in employee share ownership plans for the benefit of employee share schemes.

With effect from 1 January 2004, BP has adopted a new UK accounting standard: Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). FRS 17 requires that the assets and liabilities arising from an employer's retirement benefit obligations and any related funding should be included in the financial statements at fair value and that the operating costs of providing retirement benefits to employees should be recognized in the income statement in the periods in which the benefits are earned by employees. This contrasts with SSAP 24, which requires the cost of providing pensions to be recognized on a systematic and rational basis over the period during which the employer benefits from the employee's services. The difference between the amount charged in the income statement and the amount paid as contributions into the pension fund is shown as a prepayment or provision on the balance sheet.

Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts' (Abstract No. 38) changes the presentation of an entity's own shares held in an ESOP trust from requiring them to be recognized as assets to requiring them to be deducted in arriving at shareholders' funds. Transactions in an entity's own shares by an ESOP trust are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. This treatment is in line with the accounting for purchases and sales of own shares set out in Urgent Issues Task Force Abstract No. 37 'Purchases and Sales of Own Shares' (Abstract No. 37).

Abstract No. 37 requires a holding of an entity's own shares to be accounted for as a deduction in arriving at shareholders' funds, rather than being recorded as assets. Transactions in an entity's own shares are similarly recorded as changes in shareholders' funds and do not give rise to gains or losses. Abstract No. 37 applies where a company purchases treasury shares under new legislation that came into effect in December 2003.

Urgent Issues Task Force Abstract No. 17 'Employee share schemes' (Abstract No. 17) was amended by Abstract No. 38 to reflect the consequences for the profit and loss account of the changes in the presentation of an entity's own shares held by an ESOP trust. Amended Abstract No. 17 requires that the minimum expense should be the difference between the fair value of the shares at the date of award and the amount that an employee may be required to pay for the shares (i.e. the 'intrinsic value' of the award). The expense was previously determined either as the intrinsic value or, where purchases of shares had been made by an ESOP trust at fair value, by reference to the cost or book value of shares that were available for the award.

These changes in accounting policy have resulted in a prior year adjustment. BP shareholders' interest at 1 January 2003 has been reduced by $5,760 million and the profit for the year ended 31 December 2003 increased by $215 million.

Oil and natural gas accounting Accounting for oil and gas exploration activity is subject to special accounting rules that are unique to the oil and gas industry. In the UK, these are contained in the Statement of Recommended Practice (SORP) 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'.

The group follows the successful efforts method of accounting for its oil and natural gas exploration and production activities.

The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs.

Licence and property acquisition costs are initially capitalized as unproved properties within intangible assets. These costs are amortized on a straight-line basis until such time as either exploration drilling is determined to be successful or it is unsuccessful and all costs are written off. Licence and property acquisition costs are not subject to periodic assessments for impairment.

For exploration wells, costs directly associated with the drilling of wells are temporarily capitalized within intangible fixed assets, pending determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. These costs include employee remuneration, materials and fuel used, rig costs, delay rentals and payments made to contractors. This is usually made within one year after well completion, but can take longer, depending on the complexity of the geologic structure. If the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploration wells that discover potentially economic quantities of oil and gas and are in areas where major capital expenditure (e.g. offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration appraisal work is under way or firmly planned.

For complicated offshore exploration discoveries, it is not unusual to have exploration wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and gas field is performed or while the optimum development plans and timing are established. As with licence and property acquisition costs, there is no periodic impairment assessment of suspended exploration well costs. All such carried costs are subject to regular technical, commercial and management review, on at least an annual basis, to confirm the continued intent to develop, or otherwise extract value from, the discovery. If this is no longer the case, the costs are immediately expensed.

Once a project is sanctioned for development, the carrying values of licence and property acquisition costs and exploration and appraisal costs are transferred to production assets within tangible assets.

The capitalized exploration and development costs for proved oil and gas properties (which include the costs of drilling unsuccessful wells) are amortized on the basis of oil-equivalent barrels that are produced in a period as a percentage of the estimated proved reserves. The estimated proved reserves used in these unit-of-production calculations vary with the nature of the capitalized expenditure. The reserves used in the calculation of the unit-of-production amortization are as follows:

(a) Proved developed reserves for producing wells.
(b) Total proved reserves for development costs.
(c) Total proved reserves for licence and property acquisition costs.
(d) Total proved reserves for future decommissioning costs.

The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining book value of the asset over the expected future production. If proved reserve estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property's book value *(see discussion of impairment of fixed assets and goodwill below).*

Given the large number of producing fields in the group's portfolio, it is unlikely that any changes in reserve estimates, year on year, will have a significant effect on prospective charges for depreciation.

Oil and natural gas reserves The group manages its hydrocarbon resources in three major categories: prospect inventory, non-proved reserves and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved reserve category. The reserves move through various non-proved reserves sub-categories as their technical and commercial maturity increases through appraisal activity. Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction, or for sanction expected within six months. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves due to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

The group reassesses its estimate of proved reserves on an annual basis. The estimated proved reserves of oil and natural gas are subject to future revision. As discussed below, oil and natural gas reserves have a direct impact on certain amounts reported in the financial statements.

Proved reserves do not include reserves that are dependent on the renewal of exploration and production licences unless there is strong evidence to support the assumption of such renewal.

The group estimates its reserves of oil and natural gas according to the UK Statement of Recommended Practice. This differs from the basis for determining reserves required by the US Securities and Exchange Commission. Estimates of the group's proved reserves of oil and natural gas are shown on pages 87-92, together with more information about the group's processes for booking reserves and the difference between the reserves determined for the group's UK and US reporting.

Impairment of fixed assets and goodwill BP assesses its fixed assets, including goodwill, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable. Such indicators include changes in the group's business plans, changes in commodity prices leading to unprofitable performance and, for oil and gas properties, significant downward revisions of estimated proved reserve quantities. The assessment for impairment entails comparing the carrying value of the income-generating unit and associated goodwill with the recoverable amount of the asset, that is, the higher of net realizable value and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows.

Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas, commodity chemicals and refined products.

For oil and natural gas properties, the expected future cash flows are estimated based on the group's plans to continue to produce and develop proved and associated risk-adjusted probable and possible reserves. Expected future cash flows from the sale or production of reserves are calculated based on the group's best estimate of future oil and gas prices. Previously, these were a Brent Oil price of $20 per barrel and a Henry Hub gas price of $3.50 per mmBtu. Beginning in the fourth quarter of 2004, this has been modified. Prices used for future cash flow calculations are assumed to decline from existing levels in equal steps over the next three years to the long-term planning assumptions (currently $20/$3.50 for Brent and Henry Hub). These long-term planning assumptions are subject to periodic review and modification. The estimated future level of production is based on assumptions about future commodity prices, lifting and development costs, field decline rates, market demand and supply, economic regulatory climates and other factors.

Charges for impairment are recognized in the group's results from time to time as a result of, among other factors, adverse changes in the recoverable reserves from oil and natural gas fields, low plant utilization or reduced profitability. If there are low oil prices or natural gas prices or refining margins or chemicals margins over an extended period, the group may need to recognize significant impairment charges.

Deferred taxation The group has approximately $7.7 billion of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. It is unlikely that the group's effective tax rate will be significantly affected in the near term by utilization of losses not previously recognized as deferred tax assets. Carry-forward tax losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the group's tax rate in future years.

Deferred taxation is not generally provided in respect of liabilities that may arise on the distribution of accumulated reserves of overseas subsidiaries, joint ventures and associated undertakings.

Decommissioning costs The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest asset removal obligations facing BP relate to the removal and disposal of oil and natural gas platforms and pipelines around the world. The estimated discounted costs of dismantling and removing these facilities are accrued on the installation of those facilities, reflecting our legal obligations at that time. Most of these removal events are many years in the future and the precise requirements that will have to be met when the removal event actually occurs are uncertain. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty.

The timing and amount of future expenditures are reviewed annually, together with the interest rate to be used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2004 was 2.0%, 0.5% lower than at the end of 2003. The interest rate represents the real rate (i.e. adjusted for inflation) on long-dated government bonds.

Environmental costs BP also makes judgements and estimates in recording costs and establishing provisions for environmental clean-up and remediation costs, which are based on current information on costs and expected plans for remediation. For environmental provisions, actual costs can differ from estimates because of changes in laws and regulations, public expectations, discovery and analysis of site conditions and changes in clean-up technology.

The provision for environmental liabilities is reviewed at least annually. The interest rate used to determine the balance sheet obligation at 31 December 2004 was 2.0%, 0.5% lower than at the previous balance sheet date.

Pensions and other post-retirement benefits Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, rates of return on plan assets, determination of discount rates for measuring plan obligations, healthcare cost-trend rates and rates of utilization of healthcare services by retirees. These assumptions are based on the environment in each country. Determination of the projected benefit obligations for the group's defined benefit pension and post-retirement plans is important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. The assumptions used may vary from year to year, which will affect future results of operations. Any differences between these assumptions and the actual outcome also affect future results of operations.

Pension and other post-retirement benefit assumptions are discussed and agreed with the independent actuaries in December each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surplus and deficits recorded on the group's balance sheet, and pension and post-retirement expense for the following year.

Adoption of International Financial Reporting Standards

An 'International Accounting Standards Regulation' was adopted by the Council of the European Union (EU) in June 2002. This regulation requires all EU companies listed on an EU stock exchange to use 'endorsed' International Financial Reporting Standards (IFRS), published by the International Accounting Standards Board (IASB), to report their consolidated results with effect from 1 January 2005. The IASB completed its development of IFRS to be adopted in 2005 during the first half of 2004, but has also published certain amendments and interpretations of IFRS which would be available for early adoption if endorsed by the EU.

The process of endorsement of IFRS by the EU to allow adoption by companies in 2005 is well advanced but not yet complete.

BP's project team includes a broadly based representation from across the group designed to plan for and achieve a smooth transition to IFRS. The project team has examined all implementation aspects, including changes to accounting policies, the presentation of the group's results, systems impacts and the wider business issues that may arise from such a fundamental change. The group is now prepared to report its results from the first quarter of 2005 onwards using IFRS. However, the implementation may still be affected by developments in the IASB's standard-setting process and the endorsement of standards and interpretations by the EU.

The group has decided that, for the purposes of the restatement of prior periods currently reported under UK GAAP, the date of transition to IFRS is 1 January 2003. However, in accordance with the provisions of IFRS 1, the date of adoption of IAS Nos. 32 and 39, which deal with the recognition and presentation of financial instruments, is set at 1 January 2005, with no restatement of prior periods' results.

We are in the process of finalizing the restatements of the results and financial position for 2003 and 2004 under IFRS, and intend to release this information in mid-March 2005. Our current view is that the major effects of changing from our current accounting practice to IFRS are in the following areas: goodwill acquired in a business combination; deferred tax related to business combinations and in respect of the valuation of stocks; accounting for items falling within the scope of IAS Nos. 32 and 39, including embedded derivatives and hedge accounting; the treatment of major overhaul expenditure; exchanges of fixed assets; recognition of dividend liabilities; and share-based payments. Certain joint arrangements with third parties, where BP currently accounts for its share of individual assets, liabilities, income and expense, will be accounted for using the equity method, resulting in reclassifications within the income statement and balance sheet.

Financial risk management

The group co-ordinates certain key activities on a global basis in order to optimize its financial position and performance. These include the management of the currency, maturity and interest rate profile of finance debt, cash, other significant financial risks and relationships with banks and other financial institutions. International oil, natural gas and power trading and risk management relating to business operations are carried out by the group's oil, natural gas and power trading units.

The main financial risks faced by the group through its normal business activities are market risk, credit risk and liquidity risk. These risks and the group's approach to dealing with them are discussed below.

The adoption of IFRS from 1 January 2005 does not fundamentally change BP's approach to managing financial risk. The new requirement may, however, introduce some volatility into earnings for the recognition and measurement of certain financial instruments.

Market risk Market risk is the possibility that changes in currency exchange rates, interest rates or oil, natural gas and power prices will adversely affect the value of the group's financial assets, liabilities or expected future cash flows. Market risks are managed using a range of derivatives. The group also trades derivatives in conjunction with these risk management activities.

All derivative activity, whether for risk management or trading, is carried out by specialist teams who have the appropriate skills, experience and supervision. These teams are subject to close financial and management control. The appropriate governance, control framework and reporting processes are in place to oversee these internal control and risk management activities. On an ongoing basis, an independent control function monitors compliance with BP's policies that are in line with generally accepted industry practice, reflecting the principles of the Group of Thirty Global Derivatives Study. The control framework includes prescribed trading limits that are reviewed regularly by senior management, daily monitoring of risk exposure using value-at-risk principles, marking trading exposures to market and stress testing to assess the exposure to potentially extreme market situations.

For market risk management and trading, conventional exchange-traded derivative instruments such as futures and options are used, as well as non-exchange-traded instruments such as swaps, 'over-the-counter' options and forward contracts.

Where derivatives constitute a hedge, the group's exposure to market risk created by the derivative is offset by the opposite exposure arising from the asset, liability, cash flow or transaction being hedged. By contrast, where derivatives are held for trading purposes, changes in market risk factors give rise to gains and losses, which are recognized in earnings in the current period.

Currency exchange rates Fluctuations in exchange rates can have significant effects on the group's reported profit. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost-competitiveness, lags in market adjustment to movements in rates and conversion differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported profit.

The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major products are priced internationally in US dollars. BP's foreign exchange management policy is to minimize economic and significant transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign exchange risks centrally, by netting off naturally occurring opposite exposures wherever possible, to reduce the risks, and then dealing with any material residual foreign exchange risks. Significant residual non-dollar exposures are managed using a range of derivatives.

In addition, most group borrowings are in US dollars or are hedged with respect to the US dollar.

Interest rates The group is exposed to interest rate risk on short- and long-term floating rate instruments and as a result of the refinancing of fixed rate finance debt. The group is exposed predominantly to US dollar LIBOR (London Inter-Bank Offer Rate) interest rates as borrowings are mainly denominated in, or are swapped into, US dollars. The group uses derivatives to manage the balance between fixed and floating rate debt.

Oil, natural gas and power prices BP's trading function uses financial and commodity derivatives as part of the overall optimization of the value of the group's equity oil production and as part of the associated trading of crude oil, products and related instruments. It also uses financial and commodity derivatives to manage certain of the group's exposures to price fluctuations on natural gas and power transactions.

Credit risk Credit risk is the potential exposure of the group to loss in the event of non-performance by a counterparty. The credit risk arising from the group's normal commercial operations is controlled by individual operating units within guidelines. In addition, as a result of its use of derivatives to manage market risk, the group has credit exposures through its dealings in the financial and specialized oil, natural gas and power markets. The group controls the related credit risk through credit approvals, limits, use of netting arrangements and monitoring procedures. Counterparty credit validation, independent of the dealers, is undertaken before contractual commitment.

Concentrations of credit risk The primary activities of the group are oil and natural gas exploration and production, gas and power marketing and trading, oil refining and marketing and the manufacture and marketing of petrochemicals. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. The credit ratings of interest rate and currency swap counterparties are all of at least investment grade. The credit quality is actively managed over the life of the swap.

Liquidity risk Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group has long-term debt ratings of Aa1 and AA+ assigned respectively by Moody's and Standard and Poor's. The group has access to a wide range of funding at competitive rates through the capital markets and banks. It co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management centrally. The group believes it has access to sufficient funding and also has undrawn committed borrowing facilities to meet currently foreseeable borrowing requirements.

At 31 December 2004, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2005 ($3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The group expects to renew these facilities on an annual basis. Certain of these facilities support the group's commercial paper programme.

Insurance

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premia with attendant transaction costs. This position will be reviewed periodically.

Environmental expenditure

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table below are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

		$ million
	2004	2003
Operating expenditure	526	498
Clean-ups	25	45
Capital expenditure	524	546
New provisions for environmental remediation	588	515
New provisions for decommissioning	294	1,159

Environmental operating and capital expenditures for 2004 were broadly in line with 2003. Similar levels of operating and capital expenditures are expected in the foreseeable future. In addition to operating and capital expenditures, we also create provisions for future environmental remediation. Expenditure against such provisions is normally in subsequent periods and is not included in environmental operating expenditure reported for such periods. The charge for environmental remediation provisions in 2004 includes $484 million resulting from a reassessment of existing site obligations and $104 million in respect of provisions for new sites.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally, their timing coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions and also the group's share of liability. Although the cost of any future remediation could be significant and may be material to the result of operations in the period in which it is recognized, we do not expect that such costs will have a material effect on the group's financial position or liquidity. We believe our provisions are sufficient for known requirements; and we do not believe that our costs will differ significantly from those of other companies engaged in similar industries, or that our competitive position will be adversely affected as a result.

In addition, we make provisions over the useful lives of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. Provisions for environmental remediation and decommissioning are usually set up on a discounted basis, as required by Financial Reporting Standard No. 12, 'Provisions, Contingent Liabilities and Contingent Assets'.

Further details of our environmental and decommissioning provisions appear in Note 30 on Accounts on page 67. New provisions for decommissioning in 2004 include increases in respect of reassessment of existing provisions and new provisions for certain fields on installation of facilities.

Creditor payment policy and practice

Statutory regulations issued under the UK Companies Act 1985 require companies to make a statement of their policy and practice in respect of the payment of trade creditors.

In view of the international nature of the group's operations there is no specific group-wide policy in respect of payments to suppliers. Relationships with suppliers are, however, governed by the group's policy commitment to long-term relationships founded on trust and mutual advantage. Within this overall policy, individual operating companies are responsible for agreeing terms and conditions for their business transactions and ensuring that suppliers are aware of the terms of payment. These terms are adhered to when payments are made, subject to terms and conditions being met by the supplier.

BP p.l.c. is a holding company with no business activity other than the holding of investments in the group and therefore had no trade creditors at 31 December 2004.

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Statement of directors' responsibilities in respect of the accounts

Company law requires the directors to prepare accounts for each financial year that give a true and fair view of the state of affairs of the company and the group and of the profit or loss of the group for that period. In preparing those accounts, the directors are required:

- To select suitable accounting policies and then apply them consistently.
- To make judgements and estimates that are reasonable and prudent.
- To state whether applicable accounting standards have been followed, subject to any material departures disclosed and explained in the accounts.
- To prepare the accounts on the going concern basis unless it is inappropriate to presume that the group will continue in business.

The directors are also responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the group and enable them to ensure that the accounts comply with the Companies Act 1985. They are also responsible for taking reasonable steps to safeguard the assets of the group and to prevent and detect fraud and other irregularities.

The directors confirm that they have complied with these requirements, and having a reasonable expectation that the company has adequate resources to continue in operational existence for the foreseeable future, continue to adopt the going concern basis in preparing the accounts.

Independent auditors' report

To the Members of BP p.l.c.

We have audited the group's accounts for the year ended 31 December 2004, which comprise the group income statement, balance sheets, group cash flow statement, statement of total recognized gains and losses, accounting policies and related notes 1 to 47. These accounts have been prepared on the basis of the accounting policies set out therein. We have also audited the information in the Directors' Remuneration Report contained in *BP Annual Report and Accounts 2004* that is described as having been subject to audit.

This report is made solely to the company's members, as a body, in accordance with Section 235 of the Companies Act 1985. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditors' report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report or for the opinions we have formed.

Respective responsibilities of directors and auditors

The directors are responsible for preparing the Annual Report and Accounts, including the accounts in accordance with applicable United Kingdom law and accounting standards as set out in the statement of directors' responsibilities in respect of the accounts.

Our responsibility is to audit the accounts and the part of the Directors' Remuneration Report that is subject to audit in accordance with relevant legal and regulatory requirements, United Kingdom Auditing Standards and the Listing Rules of the Financial Services Authority.

We report to you our opinion as to whether the accounts give a true and fair view and whether the accounts and the parts of the Directors' Remuneration Report that are subject to audit have been properly prepared in accordance with the Companies Act 1985. We also report to you if, in our opinion, the Directors' Report, contained in *BP Annual Report and Accounts 2004*, is not consistent with the accounts, if the company has not kept proper accounting records, if we have not received all the information and explanations we require for our audit, or if the information specified by law or the Listing Rules regarding directors' remuneration and transactions with the group is not disclosed.

We review whether the corporate governance statement contained in *BP Annual Report and Accounts 2004* reflects the company's compliance with the nine provisions of the 2003 FRC Code specified for our review by the Listing Rules of the Financial Services Authority, and we report if it does not. We are not required to consider whether the board's statements on internal control cover all risks and controls, or form an opinion on the effectiveness of the group's corporate governance procedures or its risk and control procedures.

We read other information contained in *BP Annual Report and Accounts 2004* and consider whether it is consistent with the audited accounts. This other information comprises the United States accounting principles, the supplementary information on oil and natural gas quantities, the five-year summaries, the Directors' Report and the unaudited part of the Directors' Remuneration Report. We consider the implications for our report if we become aware of any misstatements or material inconsistencies with the accounts. Our responsibilities do not extend to any other information.

Basis of audit opinion

We conducted our audit in accordance with United Kingdom Auditing Standards issued by the Auditing Practices Board. An audit includes examination, on a test basis, of evidence relevant to the amounts and disclosures in the accounts and the parts of the Directors' Remuneration Report that are subject to audit. It also includes an assessment of the significant estimates and judgements made by the directors in the preparation of the accounts, and of whether the accounting policies are appropriate to the group's circumstances, consistently applied and adequately disclosed.

We planned and performed our audit so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the accounts and the parts of the Directors' Remuneration Report that are subject to audit are free from material misstatement, whether caused by fraud or other irregularity or error. In forming our opinion we also evaluated the overall adequacy of the presentation of information in the accounts and the part of the Directors' Remuneration Report that is subject to audit.

Opinion

In our opinion:

- the accounts give a true and fair view of the state of affairs of the company and of the group as at 31 December 2004 and of the profit of the group for the year then ended; and
- the accounts and the part of the Directors' Remuneration Report that is subject to audit have been properly prepared in accordance with the Companies Act 1985.

Ernst & Young LLP
Registered Auditor
London
7 February 2005

Accounting policies

Accounting standards
These accounts are prepared in accordance with applicable UK accounting standards. In preparing the financial statements for the current year, the group has adopted Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) and Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts' (Abstract No. 38). The adoption of FRS 17 and Abstract No. 38 has resulted in changes in accounting policy for pensions and other post-retirement benefits and the accounting of ESOP trusts. *(See Note 44 for further information.)*

In addition to the requirements of accounting standards, the accounting for exploration and production activities is governed by the Statement of Recommended Practice (SORP) 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' issued by the UK Oil Industry Accounting Committee on 7 June 2001. These accounts have been prepared in accordance with the provisions of the SORP.

Group consolidation
The group financial statements comprise a consolidation of the accounts of the parent company and its subsidiary undertakings (subsidiaries). The results of subsidiaries acquired or sold are consolidated for the periods from or to the date on which control passes.

An associated undertaking (associate) is an entity in which the group has a long-term equity interest and over which it exercises significant influence. The consolidated financial statements include the group proportion of the operating profit or loss, exceptional items, stock holding gains or losses, interest expense, taxation and net assets of associates (the equity method).

A joint venture is an entity in which the group has a long-term interest and shares control with one or more co-venturers. The consolidated financial statements include the group proportion of turnover, operating profit or loss, exceptional items, stock holding gains or losses, interest expense, taxation, gross assets, gross liabilities and minority shareholders' interest of the joint venture (the gross equity method).

Certain of the group's activities are conducted through joint arrangements and are included in the consolidated financial statements in proportion to the group's interest in the income, expenses, assets and liabilities of these joint arrangements.

On the acquisition of a subsidiary, or of an interest in a joint venture or associate, fair values reflecting conditions at the date of acquisition are attributed to the identifiable net assets acquired. When the cost of acquisition exceeds the fair values attributable to the group's share of such net assets, the difference is treated as purchased goodwill. This is capitalized and amortized on a straight-line basis over its estimated useful economic life, which is usually 10 years.

Where an interest in a separate business of an acquired entity is held temporarily, pending disposal, it is carried on the balance sheet at its estimated net proceeds of sale.

Accounting convention
The accounts are prepared under the historical cost convention, except as explained under stock valuation. Accounts prepared on this basis show the profits available to shareholders and are the most appropriate basis for presentation of the group's balance sheet. Profit or loss determined under the historical cost convention includes stock holding gains or losses and, as a consequence, does not necessarily reflect underlying trading results.

Replacement cost
The results of individual businesses and geographical areas are presented on a replacement cost basis. Replacement cost operating results exclude stock holding gains or losses and reflect the average cost of supplies incurred during the year, and thus provide insight into underlying trading results. Stock holding gains or losses represent the difference between the replacement cost of sales and the historical cost of sales calculated using the first-in first-out method.

Stock valuation
Stocks, other than stock held for trading purposes, are valued at cost to the group using the first-in first-out method or at net realizable value, whichever is the lower. Stores are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

Stock held for trading purposes is marked-to-market and any gains or losses are recognized in the income statement rather than the statement of total recognized gains and losses. The directors consider that the nature of the group's trading activity is such that, in order for the accounts to show a true and fair view of the state of affairs of the group and the results for the year, it is necessary to depart from the requirements of Schedule 4 to the Companies Act 1985. Had the treatment in Schedule 4 been followed, the profit and loss account reserve would have been reduced by $100 million ($150 million) and a revaluation reserve established and increased accordingly.

Revenue recognition
Revenues associated with the sale of oil, natural gas liquids, liquefied natural gas, petroleum and chemical products and all other items are recognized when the title passes to the customer. Supply buy/sell arrangements with common counterparties are reported net, as are physical exchanges. Oil and natural gas forward sales contracts are included in turnover. Generally, revenues from the production of natural gas and oil properties in which the group has an interest with other producers are recognized on the basis of the group's working interest in those properties (the entitlement method). Differences between the production sold and the group's share of production are not significant.

Foreign currency transactions
Foreign currency transactions by group companies are booked in the functional currency at the exchange rate ruling on the date of transaction, or at the forward rate if hedged by a forward exchange contract. Foreign currency monetary assets and liabilities are translated into the functional currency at rates of exchange ruling at the balance sheet date, or at the forward rate. Exchange differences are included in operating profit.

Assets and liabilities of overseas subsidiary and associated undertakings and joint ventures, including related goodwill, are translated into US dollars at rates of exchange ruling at the balance sheet date. The results and cash flows of overseas subsidiary and associated undertakings and joint ventures are translated into US dollars using average rates of exchange. Exchange adjustments arising when the opening net assets and the profits for the year retained by overseas subsidiary and associated undertakings and joint ventures are translated into US dollars are taken directly to reserves and reported in the statement of total recognized gains and losses. Exchange gains and losses arising on long-term foreign currency borrowings used to finance the group's foreign currency investments are also dealt with in reserves.

Derivative financial instruments

The group uses derivative financial instruments (derivatives) to manage certain exposures to fluctuations in foreign currency exchange rates and interest rates, and to manage some of its margin exposure from changes in oil, natural gas and power prices. Derivatives are also traded in conjunction with these risk management activities.

The purpose for which a derivative contract is used is identified at inception. To qualify as a derivative for risk management, the contract must be in accordance with established guidelines that ensure that it is effective in achieving its objective. All contracts not identified at inception as being for the purpose of risk management are designated as being held for trading purposes and accounted for using the fair value method, as are all oil price derivatives.

The group accounts for derivatives using the following methods:

Fair value method Derivatives are carried on the balance sheet at fair value ('marked-to-market') with changes in that value recognized in earnings of the period. This method is used for all derivatives that are held for trading purposes. Interest rate contracts traded by the group include futures, swaps, options and swaptions. Foreign exchange contracts traded include forwards and options. Oil, natural gas and power price contracts traded include swaps, options and futures.

Accrual method Amounts payable or receivable in respect of derivatives are recognized ratably in earnings over the period of the contracts. This method is used for derivatives held to manage interest rate risk. These are principally swap agreements used to manage the balance between fixed and floating interest rates on long-term finance debt. Other derivatives held for this purpose may include swaptions and futures contracts. Amounts payable or receivable in respect of these derivatives are recognized as adjustments to interest expense over the period of the contracts. Changes in the derivative's fair value are not recognized.

Deferral method Gains and losses from derivatives are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. This method is used for derivatives used to convert non-US dollar borrowings into US dollars, to hedge significant non-US dollar firm commitments or anticipated transactions, and to manage some of the group's exposure to natural gas and power price fluctuations. Derivatives used to convert non-US dollar borrowings into US dollars include foreign currency swap agreements and forward contracts. Gains and losses on these derivatives are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. Derivatives used to hedge significant non-US dollar transactions include foreign currency forward contracts and options and to hedge natural gas and power price exposures include swaps, futures and options. Gains and losses on these contracts and option premia paid are also deferred and recognized in the income statement or as adjustments to carrying amounts, as appropriate, when the hedged transaction occurs.

Where derivatives used to manage interest rate risk or to convert non-US dollar debt or to hedge other anticipated cash flows are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying debt or hedged transaction. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item.

The effect of these policies on the accounts is described as follows:

Reporting in the income statement Gains and losses on oil price contracts held for trading and for risk management purposes and natural gas and power price contracts held for trading purposes that are settled for difference in cash are reported in cost of sales in the income statement in the period in which the change in value occurs. Gains and losses on interest rate or foreign currency derivatives used for trading are reported in other income and cost of sales, respectively. Gains and losses in respect of derivatives used to manage interest rate exposures are recognized as adjustments to interest expense.

Where derivatives are used to convert non-US dollar borrowings into US dollars, the gains and losses are deferred and recognized on maturity of the underlying debt, together with the matching loss or gain on the debt. The two amounts offset each other in the income statement.

Gains and losses on derivatives identified as hedges of significant non-US dollar firm commitments or anticipated transactions are not recognized until the hedged transaction occurs. The treatment of the gain or loss arising on the designated derivative reflects the nature and accounting treatment of the hedged item. The gain or loss is recorded in cost of sales in the income statement or as an adjustment to carrying values in the balance sheet, as appropriate.

Gains and losses arising from natural gas and power price derivatives held for risk management purposes are recognized in earnings when the hedged transaction occurs. The gains or losses are reported as components of the related transactions.

Reporting in the balance sheet The carrying amounts of foreign exchange contracts that hedge finance debt are included within finance debt in the balance sheet. The carrying amounts of other derivatives, including option premia paid or received, are included in the balance sheet under debtors or creditors within current assets and current liabilities respectively, as appropriate.

Cash flow effects Interest rate swaps give rise, at specified intervals, to cash settlement of interest differentials. Under currency swaps the counterparties initially exchange a principal amount in two currencies, agreeing to re-exchange the currencies at a future date at the same exchange rate. The group's currency swaps have terms of up to six years.

Interest rate futures require an initial margin payment and daily settlement of margin calls. Interest rate forwards require settlement of the interest rate differential on a specified future date. Currency forwards require purchase or sale of an agreed amount of foreign currency at a specified exchange rate at a specified future date, generally over periods of up to three years for the group. Currency options involve the initial payment or receipt of a premium and will give rise to delivery of an agreed amount of currency at a specified future date if the option is exercised.

For oil, natural gas and power price futures and options traded on regulated exchanges, gains and losses are settled on a daily basis, while exchange liquidity requirements are funded through letters of credit or cash deposits. For swaps and over-the-counter options, BP settles with the counterparty on conclusion of the pricing period.

In the statement of cash flows, the effect of interest rate derivatives used to manage interest rate exposures is reflected in interest paid. The effect of foreign currency derivatives used for hedging non-US dollar debt is included under financing. The cash flow effects of foreign currency derivatives used to hedge non-US dollar firm commitments and anticipated transactions are included in net cash inflow from operating activities for items relating to earnings or in capital expenditure or acquisitions, as appropriate, for items of a capital nature. The cash flow effects of all oil, natural gas and power price derivatives and all traded derivatives are included in net cash inflow from operating activities.

Oil and natural gas exploration and development expenditure
Oil and natural gas exploration and development expenditure is accounted for using the successful efforts method of accounting.

Licence and property acquisition costs Exploration and property leasehold acquisition costs are capitalized within intangible fixed assets and amortized on a straight-line basis over the estimated period of exploration. Upon determination of economically recoverable reserves ('proved reserves' or 'commercial reserves'), amortization ceases and the remaining costs are aggregated with exploration expenditure and held on a field-by-field basis within intangible fixed assets. When development is sanctioned, the relevant expenditure is transferred to tangible production assets.

Exploration expenditure Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. If hydrocarbons are not found, the exploration expenditure is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. All such carried costs are subject to regular technical, commercial and management review to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. When proved reserves of oil and natural gas are determined and development is sanctioned, the relevant expenditure is transferred to tangible production assets.

Development expenditure Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within tangible production assets.

Decommissioning
Provision for decommissioning is recognized in full on the installation of oil and natural gas production facilities. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding tangible fixed asset of an amount equivalent to the provision is also created. This is subsequently depreciated as part of the capital costs of the production and transportation facilities.

Any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the fixed asset.

Depreciation
Oil and gas production assets are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, decommissioning and field development costs are amortized over total proved reserves. The field development costs subject to amortization are expenditures incurred to date together with sanctioned future development expenditure.

Other tangible and intangible assets are depreciated on the straight-line method over their estimated useful lives. The average estimated useful lives of refineries are 20 years, chemicals manufacturing plants 20 years and service stations 15 years. Other intangibles are amortized over a maximum period of 20 years.

The group undertakes a review for impairment of a fixed asset or goodwill if events or changes in circumstances indicate that the carrying amount of the fixed asset or goodwill may not be recoverable. To the extent that the carrying amount exceeds the recoverable amount, that is, the higher of net realizable value and value in use, the fixed asset or goodwill is written down to its recoverable amount. The value in use is determined from estimated discounted future net cash flows.

Maintenance expenditure
Expenditure on major maintenance, refits or repairs is capitalized where it enhances the performance of an asset above its originally assessed standard of performance; replaces an asset or part of an asset that was separately depreciated and is then written off; or restores the economic benefits of an asset that has been fully depreciated. All other maintenance expenditure is charged to income as incurred.

Petroleum revenue tax
The charge for petroleum revenue tax is calculated using a unit-of-production method.

Changes in unit-of-production factors
Changes in factors which affect unit-of-production calculations are dealt with prospectively, not by immediate adjustment of prior years' amounts.

Environmental liabilities
Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future earnings are expensed.

Liabilities for environmental costs are recognized when environmental assessments or clean-ups are probable and the associated costs can be reasonably estimated. Generally, the timing of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The amount recognized is the best estimate of the expenditure required. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Leases

Assets held under leases that result in group companies receiving substantially all risks and rewards of ownership (finance leases) are capitalized as tangible fixed assets at the estimated present value of underlying lease payments. The corresponding finance lease obligation is included within finance debt. Rentals under operating leases are charged against income as incurred.

Research

Expenditure on research is written off in the year in which it is incurred.

Interest

Interest is capitalized gross of related tax relief during the period of construction where it relates either to the financing of major projects with long periods of development or to dedicated financing of other projects. All other interest is charged against income.

Pensions and other post-retirement benefits

For defined benefit pension and other post-retirement benefit schemes, scheme assets are measured at fair value and scheme liabilities are measured on an actuarial basis using the projected unit method and discounted at an interest rate equivalent to the current rate of return on a high-quality corporate bond of equivalent currency and term to the scheme liabilities. Full actuarial valuations are obtained at least every three years and are updated at each balance sheet date. The resulting surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet.

The service cost of providing pension and other post-retirement benefits to employees for the year is charged to the income statement. The cost of making improvements to pension and other post-retirement benefits is recognized in the income statement on a straight-line basis over the period during which the increase in benefits vests. To the extent that the improvements in benefits vest immediately, the cost is recognized immediately. These costs are recognized as an operating expense.

A charge representing the unwinding of the discount on the scheme liabilities during the year is included within other finance expense.

A credit representing the expected return on the scheme assets during the year is included within other finance expense. This credit is based on the market value of the scheme assets, and expected rates of return, at the beginning of the year.

Actuarial gains and losses may result from: differences between the expected return and the actual return on scheme assets; differences between the actuarial assumptions underlying the scheme liabilities and actual experience during the year; or changes in the actuarial assumptions used in the valuation of the scheme liabilities. Actuarial gains and losses, and taxation thereon, are recognized in the statement of total recognized gains and losses.

For defined contribution schemes, contributions payable for the year are charged to the income statement as an operating expense.

Deferred taxation

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future.

In particular:

- Provision is made for tax on gains arising from the disposal of fixed assets that have been rolled over into replacement assets, only to the extent that, at the balance sheet date, there is a binding agreement to dispose of the replacement assets concerned. However, no provision is made where, on the basis of all available evidence at the balance sheet date, it is more likely than not that the taxable gain will be rolled over into replacement assets and charged to tax only where the replacement assets are sold.
- Provision is made for deferred tax that would arise on remittance of the retained earnings of overseas subsidiaries, joint ventures and associated undertakings only to the extent that, at the balance sheet date, dividends have been accrued as receivable.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted.

Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

Discounting

The unwinding of the discount on provisions is included within other finance expense. Any change in the amount recognized for environmental and other provisions arising through changes in discount rates is included within other finance expense.

Use of estimates

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

Comparative figures

Information for 2003 has been restated to reflect the transfer of natural gas liquids activities from Exploration and Production to Gas, Power and Renewables. *(See Note 45 for further information.)* In addition, certain prior year figures have been restated to conform with the 2004 presentation.

Group income statement

For the year ended 31 December

	Note	2004	2003
			$ million
Turnover		294,849	236,045
Less: Joint ventures		9,790	3,474
Group turnover	1	285,059	232,571
Replacement cost of sales		248,714	201,347
Production taxes	2	2,149	1,723
Gross profit		34,196	29,501
Distribution and administration expenses	3	14,988	14,072
Exploration expense		637	542
		18,571	14,887
Other income	4	675	786
Group replacement cost operating profit	5	19,246	15,673
Share of profits of joint ventures	5	2,933	923
Share of profits of associated undertakings	5	605	511
Total replacement cost operating profit	5	22,784	17,107
Profit (loss) on sale of businesses or termination of operations	7	(695)	(28)
Profit (loss) on sale of fixed assets	7	1,510	859
Replacement cost profit before interest and tax	5	23,599	17,938
Stock holding gains (losses)	5	1,643	16
Historical cost profit before interest and tax	5	25,242	17,954
Interest expense	8	642	644
Other finance expense	9	357	547
Profit before taxation		24,243	16,763
Taxation	12	8,282	6,111
Profit after taxation		15,961	10,652
Minority shareholders' interest (MSI)		230	170
Profit for the year		15,731	10,482
Distribution to shareholders	13	6,371	5,753
Retained profit for the year		9,360	4,729
Earnings per ordinary share – cents			
Basic	14	72.08	47.27
Diluted	14	70.79	46.83
Replacement cost results			
Historical cost profit for the year		15,731	10,482
Stock holding (gains) losses (net of MSI)		(1,643)	(16)
Replacement cost profit for the year		14,088	10,466
Earnings per ordinary share – cents			
On replacement cost profit for the year	14	64.55	47.20

Balance sheets

At 31 December

							$ million
					Group		Parent
	Note		2004		2003	2004	2003
Fixed assets							
Intangible assets	19		12,076		13,642	–	–
Tangible assets	20		96,748		91,911	–	–
Investments							
Joint ventures – Gross assets		18,244		15,265			
– Gross liabilities		(6,316)		(5,111)			
– Minority shareholders' interest		(542)		(365)			
	21	11,386		9,789			
– Loans	21	1,065		1,220			
			12,451		11,009	–	–
Associated undertakings	21		5,488		4,870	2	2
Other	21		467		1,579	87,328	55,908
			18,406		17,458	87,330	55,910
Total fixed assets			127,230		123,011	87,330	55,910
Current assets							
Stocks	22		15,698		11,617	–	–
Debtors – amounts falling due:							
Within one year	23		44,395		31,384	791	865
After more than one year	23		2,301		2,518	1,451	23,751
Investments	24		328		185	–	–
Cash at bank and in hand			1,156		1,947	4	3
			63,878		47,651	2,246	24,619
Creditors – amounts falling due within one year							
Finance debt	28		10,184		9,456	–	–
Other creditors	29		54,341		41,128	9,508	6,802
Net current assets (liabilities)			(647)		(2,933)	(7,262)	17,817
Total assets less current liabilities			126,583		120,078	80,068	73,727
Creditors – amounts falling due after more than one year							
Finance debt	28		12,907		12,869	–	–
Other creditors	29		4,505		6,030	76	50
Provisions for liabilities and charges							
Deferred taxation	12		15,050		14,371	–	–
Other provisions	30		9,608		8,599	–	–
Net assets excluding pension and other post-retirement benefit balances			84,513		78,209	79,992	73,677
Defined benefit pension plan surpluses	31		1,475		1,146	1,465	1,093
Defined benefit pension plan deficits	31		(5,863)		(5,005)	–	–
Other post-retirement benefit plan deficit	32		(2,126)		(2,630)	–	–
Net assets			77,999		71,720	81,457	74,770
Minority shareholders' interest – equity			1,343		1,125	–	–
BP shareholders' interest			76,656		70,595	81,457	74,770
Represented by							
Capital and reserves							
Called up share capital	33		5,403		5,552	5,403	5,552
Share premium account	34		5,636		3,957	5,636	3,957
Capital redemption reserve	34		730		523	730	523
Merger reserve	34		27,162		27,077	26,465	26,380
Other reserves	34		44		129	44	129
Shares held by ESOP trusts	34		(82)		(96)	(82)	(96)
Profit and loss account	34		37,763		33,453	43,261	38,325
	35		76,656		70,595	81,457	74,770

The accounts on pages 40-86 were approved by a duly appointed and authorized committee of the board of directors on 7 February 2005 and were signed on its behalf by:

Peter Sutherland, Chairman

The Lord Browne of Madingley, Group Chief Executive

Group cash flow statement

For the year ended 31 December

	Note	2004	2003
			$ million
Net cash inflow from operating activities	36	28,554	21,698
Dividends from joint ventures		1,908	131
Dividends from associated undertakings		291	417
Servicing of finance and returns on investments			
Interest received		332	175
Interest paid		(694)	(1,006)
Dividends received		53	140
Dividends paid to minority shareholders		(33)	(20)
Net cash outflow from servicing of finance and returns on investments		(342)	(711)
Taxation			
UK corporation tax		(1,447)	(1,185)
Overseas tax		(4,931)	(3,619)
Tax paid		(6,378)	(4,804)
Capital expenditure and financial investment			
Payments for tangible and intangible fixed assets		(13,035)	(12,368)
Payments for fixed assets – investments		–	(9)
Proceeds from the sale of fixed assets	17	4,323	6,253
Net cash outflow for capital expenditure and financial investment		(8,712)	(6,124)
Acquisitions and disposals			
Acquisitions, net of cash acquired		(1,503)	(211)
Proceeds from the sale of businesses	17	725	179
Acquisition of investment in TNK-BP joint venture		(1,250)	(2,351)
Net investment in other joint ventures		(272)	(178)
Investments in associated undertakings		(942)	(987)
Net cash outflow for acquisitions and disposals		(3,242)	(3,548)
Equity dividends paid		(6,041)	(5,654)
Net cash inflow (outflow)		6,038	1,405
Financing	36	6,777	1,129
Management of liquid resources	36	132	(41)
Increase (decrease) in cash	36	(871)	317
		6,038	1,405

Statement of total recognized gains and losses

For the year ended 31 December

	2004	2003
		$ million
Profit for the year	15,731	10,482
Currency translation differences	2,344	3,673
Actuarial gain relating to pensions and other post-retirement benefits	107	76
Unrealized gain on acquisition of further investment in equity-accounted investments	94	–
Tax on currency translation differences	(208)	(37)
Tax on actuarial gain relating to pensions and other post-retirement benefits	96	(16)
Total recognized gains and losses relating to the year	18,164	14,178
Prior year adjustment – change in accounting policy	(5,198)	
Total recognized gains and losses since last annual accounts	12,966	

Notes on accounts

1 Turnover

$ million

	2004	2003
Sales and operating revenue	352,316	278,859
Customs duties and sales taxes	67,257	46,288
Group turnover	285,059	232,571

Turnover[a]	Total sales	Sales between businesses	Sales to third parties	Total sales	Sales between businesses	Sales to third parties
By business						
Exploration and Production	34,914	24,756	10,158	30,753	22,885	7,868
Refining and Marketing	179,587	6,539	173,048	149,477	4,448	145,029
Petrochemicals	21,209	780	20,429	16,075	592	15,483
Gas, Power and Renewables	83,320	2,442	80,878	65,639	1,963	63,676
Other businesses and corporate	546	–	546	515	–	515
Group turnover	319,576	34,517	285,059	262,459	29,888	232,571
Share of sales by joint ventures			9,790			3,474
			294,849			236,045

	Total sales	Sales between areas	Sales to third parties	Total sales	Sales between areas	Sales to third parties
By geographical area						
UK[b]	81,155	28,484	52,671	54,971	15,275	39,696
Rest of Europe	54,422	6,928	47,494	50,582	8,672	41,910
USA	130,652	3,603	127,049	108,910	2,169	106,741
Rest of World	68,052	10,207	57,845	52,498	8,274	44,224
	334,281	49,222	285,059	266,961	34,390	232,571
Share of sales by joint ventures						
UK			155			144
Rest of Europe			296			290
USA			212			177
Rest of World			9,127			2,863
			9,790			3,474

[a]Turnover to third parties is stated by origin, which is not materially different from turnover by destination. Transfers between group companies are made at market prices taking into account the volumes involved.
[b]UK area includes the UK-based international activities of Refining and Marketing.

2 Production taxes

$ million

	2004	2003
UK petroleum revenue tax	335	300
Overseas production taxes	1,814	1,423
	2,149	1,723

3 Distribution and administration expenses

$ million

	2004	2003
Distribution	13,577	12,559
Administration	1,411	1,513
	14,988	14,072

4 Other income

$ million

	2004	2003
Income from other fixed asset investments	76	157
Other interest and miscellaneous income	599	629
	675	786
Income from listed investments included above	21	60

5 Analysis of historical cost profit

$ million

	Group replacement cost operating profit[a,b]	Joint ventures	Associated undertakings	Total replacement cost operating profit[a,b]	Exceptional items[c]	Replacement cost profit before interest and tax	Stock holding gains (losses)	Historical cost profit before interest and tax
2004								
By business								
Exploration and Production	15,185	2,948	235	18,368	152	18,520	10	18,530
Refining and Marketing	4,676	31	132	4,839	(117)	4,722	1,245	5,967
Petrochemicals[d]	(514)	(46)	223	(337)	(563)	(900)	349	(551)
Gas, Power and Renewables	872	–	15	887	56	943	39	982
Other businesses and corporate[e]	(973)	–	–	(973)	1,287	314	–	314
	19,246	2,933	605	22,784	815	23,599	1,643	25,242
By geographical area								
UK[f]	2,267	(6)	9	2,270	(343)	1,927	138	2,065
Rest of Europe	2,758	(14)	34	2,778	(87)	2,691	379	3,070
USA	8,151	29	70	8,250	(205)	8,045	888	8,933
Rest of World	6,070	2,924	492	9,486	1,450	10,936	238	11,174
	19,246	2,933	605	22,784	815	23,599	1,643	25,242
2003								
By business								
Exploration and Production	12,567	914	272	13,753	913	14,666	3	14,669
Refining and Marketing	2,367	29	135	2,531	(213)	2,318	(48)	2,270
Petrochemicals[d]	461	(20)	89	530	38	568	55	623
Gas, Power and Renewables	579	–	(3)	576	(6)	570	6	576
Other businesses and corporate[e]	(301)	–	18	(283)	99	(184)	–	(184)
	15,673	923	511	17,107	831	17,938	16	17,954
By geographical area								
UK[f]	1,941	(22)	14	1,933	717	2,650	(9)	2,641
Rest of Europe	2,484	2	15	2,501	(151)	2,350	(230)	2,120
USA	6,177	26	79	6,282	(347)	5,935	390	6,325
Rest of World	5,071	917	403	6,391	612	7,003	(135)	6,868
	15,673	923	511	17,107	831	17,938	16	17,954

[a] Replacement cost operating profit is before stock holding gains and losses and interest expense, which is attributable to the corporate function. Transfers between group companies are made at market prices taking into account the volumes involved.
[b] Accounted net foreign currency exchange gains included in the determination of profit for the year amounted to $41 million ($171 million gains).
[c] Exceptional items comprise profit or loss on the sale of fixed assets and the sale of businesses or termination of operations.
[d] Includes $39 million stock holding losses ($4 million gains) in respect of joint ventures and associated undertakings.
[e] Other businesses and corporate comprises Finance, the group's coal asset (divested in October 2003) and aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide.
[f] UK area includes the UK-based international activities of Refining and Marketing.

6 Hire charges and expenditure on research

$ million

	2004	2003
Hire charges under operating leases		
Tanker charters	747	440
Plant and machinery	428	457
Land and buildings	555	548
	1,730	1,445
Expenditure on research	439	349

7 Exceptional items

	2004	2003
	$ million	
Loss on sale of businesses or termination of operations	(695)	(28)
	(695)	(28)
Profit on sale of fixed assets	1,829	1,894
Loss on sale of fixed assets	(319)	(1,035)
Exceptional items	815	831
Taxation credit (charge)		
Sale of businesses or termination of operations	238	–
Sale of fixed assets	23	(123)
Exceptional items (net of tax)	1,076	708

Exceptional items comprise profit (loss) on sale of fixed assets and the sale of businesses or termination of operations. The principal transactions giving rise to these profits and losses for each segment are described below.

Loss on sale of businesses or termination of operations

Refining and Marketing $132 million ($28 million) The closure of the lubricants operation of the Coryton refinery in the UK and of refining operations at the ATAS refinery in Mersin, Turkey. For 2003, the sale of the group's European oil speciality products business.

Petrochemicals $563 million (nil) The sale of the speciality intermediate chemicals business; the sale of the fabrics and fibres business; the closure of two manufacturing plants at Hull, UK, which produced acids; and the closure of the linear alpha-olefins production facility at Pasadena, Texas.

Profit on sale of fixed assets

Exploration and Production $379 million ($1,591 million) The group divested interests in a number of oil and natural gas properties in both years. For 2004, this included interests in oil and natural gas properties in Australia, Canada and the Gulf of Mexico, and the reversal of the provision for the loss on sale of $217 million for the Desarrollo Zuli Occidental (DZO) and Boqueron fields in Venezuela *(see below)*. For 2003, the divestment of a further 20% interest in BP Trinidad and Tobago LLC to Repsol; the sale of the group's 96.14% interest in the Forties oil field in the UK North Sea; the sale of a package of UK Southern North Sea gas fields; and the divestment of our interest in the In Amenas gas condensate project in Algeria to Statoil.

Refining and Marketing $107 million ($69 million) The sale of the Cushing and other pipeline interests in the US and the churn of retail assets. *In 2003, the divestment of pipeline interests in the US.*

Gas, Power and Renewables $56 million ($11 million) The divestment of BP's interest in two natural gas liquids plants in Canada. For 2003, the sale and leaseback of rail cars.

Petrochemicals nil ($55 million) For 2003, the sale of our interest in AG International Chemical Company, a purified isophthalic acid associated undertaking in Japan and other minor divestments.

Other businesses and corporate $1,287 million ($148 million) The divestment of the group's investments in PetroChina and Sinopec. In 2003, the group sold its 50% interest in Kaltim Prima Coal, an Indonesian company, and certain other investments.

Loss on sale of fixed assets

Exploration and Production $227 million ($678 million) The group divested interests in a number of oil and natural gas properties in both years. For 2004, this included interests in oil and natural gas properties in Indonesia and the Gulf of Mexico. In 2003, this included losses on exploration and production properties in China, Norway and the US and the provision for losses on sale in early 2004 of exploration and production properties in Canada and Venezuela. In respect of Venezuela, the sales agreement for our interests in the DZO and Boqueron fields lapsed in early 2004, and the fields have been retained. The provision for a loss on disposal of $217 million recognized in 2003 was reversed in 2004 and an impairment charge of $186 million was recognized.

Refining and Marketing $92 million ($274 million) The divestment of the Singapore refinery and retail churn. For 2003, retail churn and the sale of refinery *and retail* interests in Germany and Central Europe.

Gas, Power and Renewables nil ($17 million)

Petrochemicals nil ($17 million)

Other businesses and corporate nil ($49 million)

Additional information on the sale of businesses and fixed assets is given in Note 17 Disposals.

8 Interest expense

$ million

	2004	2003
Bank loans and overdrafts	34	38
Other loans[a]	573	628
Finance leases	37	34
	644	700
Capitalized at 3% (3%)[b]	208	190
Group	436	510
Joint ventures	158	89
Associated undertakings	48	45
Total charged against profit	642	644

[a] Interest expense for 2003 includes a charge of $31 million relating to early redemption of debt.
[b] Tax relief on capitalized interest is $73 million ($68 million).

9 Other finance expense

$ million

	2004	2003
Interest on pension and other post-retirement benefit plan liabilities	2,012	1,840
Expected return on pension and other post-retirement benefit plan assets	(1,983)	(1,500)
Interest net of expected return on plan assets	29	340
Unwinding of discount on provisions	196	173
Unwinding of discount on deferred consideration for acquisition of investment in TNK-BP	91	34
Change in discount rate for provisions[a]	41	–
Total charged against profit	357	547

[a] Revaluation of environmental and other provisions at a lower discount rate.

10 Auditors' remuneration

$ million

	2004		2003	
Audit fees – Ernst & Young	UK	Total	UK	Total
Group audit	13	27	8	18
Audit-related regulatory reporting	4	7	2	5
Statutory audit of subsidiaries	4	16	3	13
	21	50	13	36
Fees for other services – Ernst & Young				
Further assurance services				
Acquisition and disposal due diligence	6	7	9	9
Pension scheme audits	–	1	–	1
Other further assurance services	6	9	5	9
Tax services				
Compliance services	3	13	3	17
Advisory services	–	1	–	2
	15	31	17	38

Group audit fees for 2004 include $1 million of additional fees for 2003. Group audit fees include $4 million ($2 million) in respect of the parent company. Audit fees are included in the income statement within distribution and administration expenses.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Fees paid to major firms of accountants other than Ernst & Young for other services amount to $82 million ($44 million).

11 Depreciation and amounts provided

Included in the income statement under the following headings:	2004	2003
		$ million
Depreciation and amortization of goodwill and other intangibles		
Replacement cost of sales	11,109	9,748
Distribution	1,334	1,044
Administration	128	148
	12,571	10,940
Amounts provided against fixed asset investments		
Replacement cost of sales	12	–
	12,583	10,940
Depreciation of capitalized leased assets included above	164	46

The charge for depreciation and amortization of goodwill and other intangibles in 2004 includes asset write-downs and impairment charges of $1,743 million in total. Exploration and Production recognized a charge of $621 million for the impairment of certain assets. During the year, as a result of impairment triggers, reviews were conducted which have resulted in impairment charges of $83 million in respect of King's Peak in the Gulf of Mexico, $20 million in respect of two fields in the Gulf of Mexico Shelf Matagorda Island area and $184 million in respect of various US onshore fields. A charge of $88 million was reflected in respect of a gas processing plant in the US and a charge of $60 million following the blow-out of the Temsah platform in Egypt. In addition, following the lapse of the sale agreement for DZO and Boqueron in Venezuela, an impairment charge of $186 million was reflected. In connection with the Solvay transactions, the group has recognized impairment charges of $325 million for goodwill and $306 million for tangible fixed assets in BP Solvay Polyethylene Europe. As part of a restructuring of the North American Olefins and Derivatives businesses, decisions were taken to exit certain businesses and facilities resulting in impairments and write-downs of $291 million. With the formation of Olefins and Derivatives and its planned divestment, certain agreements and assets have been restructured to reflect the arm's-length relationship that will exist in the future. This has resulted in a $188 million impairment of the facilities at Hull, UK. Other businesses and corporate recognized an impairment charge of $12 million for certain investments.

The 2003 charge for depreciation and amortization of goodwill and other intangibles includes asset write-downs and impairment charges on exploration and production properties of $738 million. This includes a charge of $296 million for four fields in the Gulf of Mexico following technical reassessment and re-evaluation of future investment options; charges of $133 million and $49 million respectively for the Miller and Viscount fields in the UK North Sea as a result of a decision not to proceed with waterflood and gas import options and a reserve write-down respectively; a charge of $105 million for the Yacheng field in China; a charge of $108 million for the Kepadong field in Indonesia; and $47 million for the Eugene Island/West Cameron fields in the US as a result of reserve write-downs following completion of our routine full technical reviews.

In assessing the value in use of potentially impaired assets, a nominal discount rate of 9% before tax has been used. Asset values are determined by deriving the net present value of the future cash flows; the cash flows are adjusted for the risks specific to the asset.

12 Taxation

$ million

Tax on profit on ordinary activities	2004	2003
Current tax		
UK corporation tax	8,917	11,435
Overseas tax relief	(7,078)	(10,293)
	1,839	1,142
Overseas	5,070	3,525
Group	6,909	4,667
Joint ventures	880	158
Associated undertakings	119	94
	7,908	4,919
Deferred tax		
UK	(140)	289
Overseas	340	931
Group	200	1,220
Joint ventures	170	(14)
Associated undertakings	4	(14)
	374	1,192
Tax on profit on ordinary activities	8,282	6,111

Included in the charge for the year is a credit of $261 million ($123 million charge) relating to exceptional items.

$ million

Tax included in statement of total recognized gains and losses	2004	2003
Current tax		
UK	43	–
Overseas	(20)	(11)
	23	(11)
Deferred tax		
UK	165	64
Overseas	(76)	–
	89	64
Tax included in statement of total recognized gains and losses	112	53

Factors affecting current tax charge

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective current tax rate of the group on profit before taxation.

$ million

	2004	2003
Analysis of profit before taxation		
UK	7,671	4,990
Overseas	16,572	11,773
	24,243	16,763
Taxation	8,282	6,111
Effective tax rate	34%	36%

	% of profit before tax	
UK statutory corporation tax rate	30	30
Increase (decrease) resulting from		
UK supplementary and overseas taxes at higher rates	8	10
Tax credits	–	(1)
Restructuring benefits	(2)	(2)
Current year losses unrelieved (prior year losses utilized)	(2)	(3)
No relief for inventory holding losses (inventory holding gains not taxed)	(2)	(1)
Acquisition amortization	3	4
Other	(1)	(1)
Effective tax rate	34	36
Current year timing differences	(1)	(6)
Effective current tax rate	33	30

Current year timing differences arise mainly from the excess of tax depreciation over book depreciation.

12 Taxation *continued*

Factors that may affect future tax charges

From 1 January 2005, the group has adopted International Financial Reporting Standards (IFRS). As a consequence, there will be a change in the basis of providing deferred taxation in such areas as business combinations and the valuation of stock, which will lead to changes to certain of the factors described below and may lead to a change in the group's effective tax rate.

The group earns income in many different countries and, on average, pays taxes at rates higher than the UK statutory rate. The overall impact of these higher taxes, which include the supplementary charge of 10% on UK North Sea profits, is subject to changes in enacted tax rates and the country mix of the group's income. However, it is not expected to change significantly in the near term.

The group has around $7.7 billion ($4.5 billion) of carry-forward tax losses in the UK and Germany, which would be available to offset against future taxable income. At the end of 2004, no tax assets were recognized on these losses (at the end of 2003, $285 million of assets were recognized). Tax assets are recognized only to the extent that it is considered more likely than not that suitable taxable income will arise. Carry-forward losses in other taxing jurisdictions have not been recognized as deferred tax assets, and are unlikely to have a significant effect on the group's tax rate in future years.

The group's profit before taxation includes stock holding gains or losses. These gains (or losses) are not taxed (or deductible) in certain jurisdictions in which the group operates, and therefore give rise to decreases or increases in the effective tax rate. The impact of this item will be reduced under IFRS.

The impact on the tax rate of acquisition amortization (non-deductible depreciation and amortization relating to the fixed asset revaluation adjustments and goodwill consequent upon the ARCO and Burmah Castrol acquisitions) is likely to be eliminated when the group reports its results under IFRS.

The major component of timing differences in the current year is accelerated tax depreciation. Based on current capital investment plans, the group expects to continue to be able to claim tax allowances in excess of depreciation in future years at a level similar to the current year.

Deferred tax

		$ million
	2004	2003
Analysis of provision		
Depreciation	15,936	15,613
Other taxable timing differences	2,090	1,882
Petroleum revenue tax	(578)	(601)
Decommissioning and other provisions	(2,142)	(2,256)
Pensions and other post-retirement benefits	(1,720)	(1,652)
Tax credit and loss carry forward	(51)	(105)
Other deductible timing differences	(205)	(162)
Deferred tax provision	13,330	12,719
of which – UK	3,932	4,179
– Overseas	9,398	8,540

		$ million
	2004	2003
Analysis of movements during the year		
At 1 January	12,719	10,894
Exchange adjustments	329	541
Charge for the year on ordinary activities	200	1,220
Charge for the year in the statement of total recognized gains and losses	89	64
Deletions/transfers	(7)	–
At 31 December	13,330	12,719
of which – pensions	147	172
– other post-retirement benefits	1,573	1,480
	15,050	14,371

		$ million
	2004	2003
The charge for deferred tax on ordinary activities		
Origination and reversal of timing differences	200	1,220
	200	1,220
The charge for deferred tax in the statement of total recognized gains and losses		
Origination and reversal of timing differences	89	64

13 Distribution to shareholders

	pence per share		cents per share		$ million	
	2004	2003	2004	2003	2004	2003
Preference dividends (non-equity)					2	2
Dividends per ordinary share						
First quarterly	3.807	3.947	6.75	6.25	1,483	1,386
Second quarterly	3.860	4.039	7.10	6.50	1,535	1,433
Third quarterly	3.910	3.857	7.10	6.50	1,530	1,438
Fourth quarterly	4.522	3.674	8.50	6.75	1,821	1,494
	16.099	15.517	29.45	26.00	6,371	5,753

14 Earnings per ordinary share

	cents per share	
	2004	2003
Basic earnings per share	72.08	47.27
Diluted earnings per share	70.79	46.83

The calculation of basic earnings per ordinary share is based on the profit attributable to ordinary shareholders, i.e. profit for the year less preference dividends, related to the weighted average number of ordinary shares outstanding during the year. The profit attributable to ordinary shareholders is $15,729 million ($10,480 million). The average number of shares outstanding excludes the shares held by the Employee Share Ownership Plans.

The calculation of diluted earnings per share is based on profit attributable to ordinary shareholders, adjusted for the unwinding of the discount on the deferred consideration for the acquisition of our interest in TNK-BP, of $15,793 million ($10,504 million). The number of shares outstanding is adjusted to show the potential dilution if employee share options are converted into ordinary shares, and for the ordinary shares issuable, in two further annual tranches, in respect of the TNK-BP joint venture. The number of ordinary shares outstanding for basic and diluted earnings per share may be reconciled as follows:

	shares thousand	
	2004	2003
Weighted average number of ordinary shares	21,820,535	22,170,741
Potential dilutive effect of ordinary shares issuable under employee share schemes	74,775	71,651
Potential dilutive effect of ordinary shares issuable as consideration for BP's interest in the TNK-BP joint venture	415,016	186,980
	22,310,326	22,429,372

In addition to basic earnings per share based on the historical cost profit for the year, a further measure, based on replacement cost profit for the year, is provided as it is considered that this measure gives an indication of underlying performance.

	cents per share	
	2004	2003
Profit for the year	72.08	47.27
Stock holding (gains) losses	(7.53)	(0.07)
Replacement cost profit for the year	64.55	47.20

15 Operating leases

				$ million
		2004		2003
Annual commitments under operating leases	Land and buildings	Other	Land and buildings	Other
Expiring within				
1 year	79	359	70	186
2 to 5 years	180	261	173	388
Thereafter	268	387	262	291
	527	1,007	505	865
Minimum future lease payments		Total		Total
Payable within				
1 year		1,450		1,275
2 to 5 years		3,550		3,488
Thereafter		3,091		3,352
		8,091		8,115

16 Acquisitions

			$ million
			2004
	Book value on acquisition	Fair value adjustments	Fair value
Intangible fixed assets	15	–	15
Tangible fixed assets	703	636	1,339
Current assets (excluding cash)	721	–	721
Cash at bank and in hand	36	–	36
Other creditors	(329)	–	(329)
Pension liability	(3)	–	(3)
Net investment in equity-accounted entities transferred to full consolidation	(547)	(94)	(641)
Net assets acquired	596	542	1,138
Negative goodwill			(61)
Goodwill			328
Consideration			1,405

Acquisitions in 2004

On 2 November 2004, Solvay exercised its option to sell its interests in BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America to BP. Solvay held 50% of BP Solvay Polyethylene Europe and 51% of BP Solvay Polyethylene North America. On completion, the two entities, which manufacture and market high-density polyethylene, became wholly owned subsidiaries of BP. The total consideration for the acquisition was $1,391 million. The consideration is subject to final closing adjustments. Other minor acquisitions were made for a total consideration of $14 million. All business combinations have been accounted for using the acquisition method of accounting. The fair value of the tangible fixed assets has been estimated by determining the net present value of future cash flows. No significant adjustments were made to the other assets and liabilities acquired. The assets and liabilities acquired as part of the 2004 acquisitions are shown in aggregate in the table above.

During the year, BP China and Sinopec announced the establishment of the BP-Sinopec (Zhejiang) Petroleum Co. Ltd, a retail joint venture between BP and Sinopec. Based on the existing service station network of Sinopec, the new joint venture will build, operate and manage a network of 500 service stations in Hangzhou, Ningbo and Shaoxing. Also during the year, BP China and PetroChina announced the establishment of BP-PetroChina Petroleum Company Limited. Located in Guangdong, one of the most developed provinces in China, the joint venture will acquire, build, operate and manage 500 service stations in the province. The initial investment in both joint ventures amounted to $106 million.

Acquisitions in 2003

BP made a number of minor acquisitions in 2003 for a total consideration of $82 million. All these business combinations were accounted for using the acquisition method of accounting. No significant fair value adjustments were made to the acquired assets and liabilities. Goodwill of $5 million arose on these acquisitions. In addition, the group redeemed the outstanding stock in CH-Twenty, Inc., a subsidiary undertaking, for $150 million.

TNK-BP

On 29 August 2003, BP and the Alfa Group and Access-Renova (AAR) combined certain of their Russian and Ukranian oil and gas businesses to create TNK-BP, a new company owned and managed 50:50 by BP and AAR. TNK-BP is a joint venture and accounted for under the gross equity method. BP contributed its 29% interest in Sidanco, its 29% interest in Rusia Petroleum and its holding in the BP Moscow retail network. There was additional consideration from BP to AAR comprising an immediate $2,604 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends net of other adjustments, of $298 million) together with annual tranches of $1,250 million in BP shares payable in 2004, 2005 and 2006. There were costs of $45 million in connection with the transaction. The first tranche was issued in September 2004.

BP also agreed with AAR to incorporate AAR's 50% interest in Slavneft into TNK-BP in return for $1,418 million in cash (which was subsequently reduced by receipt of pre-acquisition dividends of $64 million to $1,354 million). This transaction was completed on 16 January 2004.

17 Disposals

As part of the strategy to upgrade the quality of its asset portfolio, the group has an active programme to dispose of non-strategic assets. In the normal course of business in any particular year, the group may sell interests in exploration and production properties, service stations and pipeline interests as well as non-core businesses. Disposal proceeds also include monies received from the repayment of loans.

Cash received during the year from disposals amounted to $5.0 billion ($6.4 billion). The major transactions in 2004 which generated over $2.3 billion of proceeds were the sale of the group's investments in PetroChina and Sinopec. For 2003, the major disposals representing over $3.0 billion of the proceeds were the divestment of a further 20% interest in BP Trinidad and Tobago LLC; the sale of 50% of our interest in the In Amenas gas condensate project and 49% of our interest in the In Salah gas development in Algeria; and the sale of the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico. The principal transactions generating the proceeds for each segment are described below.

Exploration and Production $921 million ($4,867 million) The group divested interests in a number of oil and natural gas properties in both years. During 2004, in the US we sold 45% of our interest in King's Peak in the deepwater Gulf of Mexico to Marubeni Oil & Gas; divested our interest in Swordfish; and additionally, we sold various properties including our interest in the South Pass 60 property in the Gulf of Mexico Shelf. In Canada, BP sold various assets in Alberta to Fairborne Energy. In Indonesia, we disposed of our interest in the Kangean Production Sharing Contract and our participating interest in the Muriah Production Sharing Contract. In 2003, the UK North Sea Forties oil field, together with a package of 61 shallow-water assets in the Gulf of Mexico, were sold to Apache. A 12.5% interest in the Tangguh liquefied natural gas project in Indonesia was sold to CNOOC. Interests in 14 UK Southern North Sea gas fields, together with associated pipelines and onshore processing facilities, including the Bacton terminal, were sold to Perenco. BP sold 50% of its interest in the In Amenas gas condensate project and 49% of its interest in the In Salah gas development in Algeria to Statoil. In January 2003, Repsol exercised its option to acquire a further 20% interest in BP Trinidad and Tobago LLC. BP's interest in the company is now 70%. In February 2003, BP called its $420 million Exchangeable Bonds which were exchangeable for Lukoil American Depositary Shares (ADSs). Bondholders converted to ADSs before the redemption date.

Refining and Marketing $906 million ($1,053 million) The churn of retail assets represents a significant element of the total in both years. In addition, for 2004, major asset transactions included the sale of the Singapore refinery, and the Cushing and other pipeline interests in the US. As a condition of the approval of the acquisition of Veba in 2002, BP was, among other things, required to divest approximately 4% of its retail market share in Germany and a significant portion of its Bayernoil refining interests. The sale of 494 retail sites in the northern and north-eastern part of Germany to PKN Orlen and the sale of retail and refinery assets in Germany and Central Europe to OMV in 2003 completed the divestments required.

Petrochemicals $717 million ($236 million) In 2004, these related principally to the sale of the speciality intermediate chemicals and fabrics and fibres businesses. For 2003, the proceeds related to the completion of the divestment of the former Burmah Castrol speciality chemicals business Sericol and Fosroc Mining.

Gas, Power and Renewables $144 million ($67 million) In 2004, the group sold its interest in two Canadian natural gas liquids plants.

Other businesses and corporate $2,360 million ($209 million) The disposal of the group's investments in PetroChina and Sinopec were the major transactions in 2004. In 2003, the group sold its 50% interest in Kaltim Prima Coal, an Indonesian company.

Total proceeds received for disposals represent the following amounts shown in the cash flow statement:

		$ million
	2004	2003
Proceeds from the sale of businesses	725	179
Proceeds from the sale of fixed assets	4,323	6,253
	5,048	6,432

		$ million
	2004	2003
The disposals comprise the following		
Intangible assets	215	322
Tangible assets[a]	2,549	6,212
Fixed assets – investments	1,197	890
Finance debt	-	(420)
Current assets less current liabilities	417	(498)
Other provisions	(105)	(971)
	4,273	5,535
Profit (loss) on sale of businesses or termination of operations	(695)	(28)
Profit (loss) on sale of fixed assets	1,510	859
Total consideration	5,088	6,366
(Increase) decrease in amounts receivable from disposals	(40)	66
Net cash inflow	5,048	6,432

[a] 2003 includes provision for loss on disposal of $275 million.

18 Group balance sheet analysis

$ million

	Capital expenditure and acquisitions		Operating capital employed	
	2004	2003	2004	2003
By business				
Exploration and Production	11,193	15,370	68,718	63,618
Refining and Marketing	3,014	3,080	38,577	35,111
Petrochemicals	2,289	775	14,755	13,484
Gas, Power and Renewables	538	441	4,901	4,292
Other businesses and corporate	215	346	(8,559)	(6,392)
	17,249	20,012	118,392	110,113
By geographical area				
UK[a]	1,832	1,556	21,342	18,788
Rest of Europe	2,105	1,277	13,109	11,030
USA	6,301	6,291	43,507	44,322
Rest of World	7,011	10,888	40,434	35,973
	17,249	20,012	118,392	110,113
Operating capital employed			118,392	110,113
Liabilities for current and deferred taxation			(17,302)	(16,068)
Capital employed			101,090	94,045
Financed by				
Finance debt			23,091	22,325
Minority shareholders' interest			1,343	1,125
BP shareholders' interest			76,656	70,595
			101,090	94,045

[a]UK area includes the UK-based international activities of Refining and Marketing.

19 Intangible assets

$ million

	Goodwill	Negative goodwill	Total goodwill	Exploration expenditure	Other intangibles	Total
Cost						
At 1 January 2004	14,384	–	14,384	4,977	833	20,194
Exchange adjustments	451	–	451	41	57	549
Acquisitions	328	(61)	267	–	15	282
Additions	–	–	–	754	246	1,000
Transfers	–	–	–	(1,036)	–	(1,036)
Deletions	(96)	–	(96)	(425)	–	(521)
At 31 December 2004	15,067	(61)	15,006	4,311	1,151	20,468
Depreciation						
At 1 January 2004	5,215	–	5,215	741	596	6,552
Exchange adjustments	194	–	194	1	40	235
Charge for the year	1,761	–	1,761	274	72	2,107
Transfers	–	–	–	(196)	–	(196)
Deletions	(36)	–	(36)	(270)	–	(306)
At 31 December 2004	7,134	–	7,134	550	708	8,392
Net book amount						
At 31 December 2004	7,933	(61)	7,872	3,761	443	12,076
At 31 December 2003	9,169	–	9,169	4,236	237	13,642

20 Tangible assets – property, plant and equipment

$ million

	Land	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total	Of which: assets under construction
Cost									
At 1 January 2004	4,442	3,745	96,991	46,413	3,482	11,738	8,969	175,780	13,957
Exchange adjustments	493	71	1,641	2,461	37	182	718	5,603	158
Acquisitions	10	–	–	1,329	–	–	–	1,339	–
Additions	308	121	8,048	2,201	513	852	861	12,904	10,084
Transfers	–	–	1,036	–	–	–	–	1,036	(8,879)
Deletions	(123)	(415)	(3,749)	(2,770)	(314)	(365)	(688)	(8,424)	(282)
At 31 December 2004	5,130	3,522	103,967	49,634	3,718	12,407	9,860	188,238	15,038
Depreciation									
At 1 January 2004	702	1,351	50,028	19,590	1,793	6,324	4,081	83,869	
Exchange adjustments	90	9	948	1,064	3	83	365	2,562	
Charge for the year	50	116	5,871	3,182	334	278	907	10,738	
Transfers	–	–	196	–	–	–	–	196	
Deletions	(89)	(285)	(3,031)	(1,539)	(370)	(202)	(359)	(5,875)	
At 31 December 2004	753	1,191	54,012	22,297	1,760	6,483	4,994	91,490	
Net book amount									
At 31 December 2004	4,377	2,331	49,955	27,337	1,958	5,924	4,866	96,748	15,038
At 31 December 2003	3,740	2,394	46,963	26,823	1,689	5,414	4,888	91,911	13,957

Assets held under finance leases, capitalized interest, decommissioning asset and land at net book amount included above:

$ million

	Leased assets			Capitalized interest		
	Cost	Depreciation	Net	Cost	Depreciation	Net
At 31 December 2004	2,831	1,127	1,704	3,881	2,547	1,334
At 31 December 2003	2,737	955	1,782	3,281	2,127	1,154

$ million

	Decommissioning asset		
	Cost	Depreciation	Net
At 31 December 2004	4,425	1,908	2,517
At 31 December 2003	3,686	1,606	2,080

$ million

	Freehold land	Leasehold land	
		Over 50 years unexpired	Other
At 31 December 2004	4,177	116	84
At 31 December 2003	3,466	71	203

21 Fixed assets – investments

$ million

Group	Joint ventures: Net assets (liabilities)	Joint ventures: Loans	Associated undertakings: Net assets (liabilities)	Associated undertakings: Loans	Other loans	Listed investments[a]	Other[b]	Total
Cost								
At 1 January 2004	9,789	1,220	3,992	1,076	129	1,284	179	17,669
Exchange adjustments	18	–	44	9	1	20	6	98
Additions and net movements in joint ventures and associated undertakings	494	(155)	117	682	–	–	–	1,138
Acquisitions	1,472	–	–	–	–	–	–	1,472
Transfers	(387)	–	20	(180)	–	–	–	(547)
Deletions	–	–	(73)	(57)	(55)	(1,041)	(28)	(1,254)
At 31 December 2004	11,386	1,065	4,100	1,530	75	263	157	18,576
Amounts provided								
At 1 January 2004	–	–	21	177	2	–	11	211
Exchange adjustments	–	–	1	–	–	–	3	4
Provided in the year	–	–	–	–	–	–	12	12
Transfers	–	–	–	–	–	–	–	–
Deletions	–	–	–	(57)	–	–	–	(57)
At 31 December 2004	–	–	22	120	2	–	26	170
Net book amount								
At 31 December 2004	11,386	1,065	4,078	1,410	73	263	131	18,406
At 31 December 2003	9,789	1,220	3,971	899	127	1,284	168	17,458

$ million

Parent	Subsidiary undertakings[c]: Shares	Associated undertakings[c]: Shares	Associated undertakings[c]: Loans	Total
Cost				
At 1 January 2004	55,913	2	2	55,917
Exchange adjustments	–	–	–	–
Additions	31,517	–	–	31,517
Deletions	(85)	–	–	(85)
At 31 December 2004	87,345	2	2	87,349
Amounts provided				
At 1 January 2004	5	–	2	7
Provided in the year	12	–	–	12
At 31 December 2004	17	–	2	19
Net book amount				
At 31 December 2004	87,328	2	–	87,330
At 31 December 2003	55,908	2	–	55,910

[a] The market value of listed investments at 31 December 2004 was $543 million ($3,212 million).
[b] Other investments are unlisted.
[c] Substantially all the investments in subsidiary and associated undertakings are unlisted.

22 Stocks

$ million

	2004	2003
Petroleum	9,612	6,623
Chemicals	1,771	1,165
Other	474	961
	11,857	8,749
Stores	925	938
	12,782	9,687
Trading stocks	2,916	1,930
	15,698	11,617
Replacement cost	15,765	11,717

23 Debtors

$ million

	Group				Parent			
	2004		2003		2004		2003	
	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year
Trade	31,223	–	23,487	–	–	–	–	–
Group undertakings	–	–	–	–	647	1,411	774	23,715
Joint ventures	14	–	44	–	–	–	–	–
Associated undertakings	210	23	337	53	–	–	–	–
Prepayments and accrued income	7,188	1,874	3,445	2,023	–	–	6	–
Taxation recoverable	157	2	78	14	–	–	–	–
Other	5,603	402	3,993	428	144	40	85	36
	44,395	2,301	31,384	2,518	791	1,451	865	23,751

24 Current assets – investments

$ million

	2004	2003
Listed		
UK	21	42
Foreign	42	37
	63	79
Unlisted	265	106
	328	185
Stock exchange value of listed investments	63	79

25 Financial instruments

An outline of the group's financial risks and the policies and objectives pursued in relation to those risks is set out in the financial risk management section of Other Financial Issues on pages 35-36.

Financial instruments comprise primary financial instruments (cash, fixed and current asset investments, debtors, creditors, finance debt and provisions) and derivative financial instruments (interest rate contracts, foreign exchange contracts, oil price contracts, natural gas price contracts and power price contracts). Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forwards, futures contracts, swap agreements and options. Oil, natural gas and power price contracts are those that require settlement in cash and include futures contracts, swap agreements and options. Oil, natural gas and power price contracts that require physical delivery are not financial instruments. However, if it is normal market practice for a particular type of oil, natural gas and power contract, despite having contract terms that require settlement by delivery, to be extinguished other than by physical delivery (e.g. by cash payment), it is called a cash-settled commodity contract. Contracts of this type are included with derivatives in the disclosures in Notes 26 and 27.

With the exception of the table of currency exposures shown on page 61, short-term debtors and creditors that arise directly from the group's operations have been excluded from the disclosures contained in this note, as permitted by Financial Reporting Standard No. 13 'Derivatives and Other Financial Instruments: Disclosures'.

Maturity profile of financial liabilities

The profile of the maturity of the financial liabilities included in the group's balance sheet at 31 December is shown in the table below.

$ million

	2004			2003		
	Finance debt	Other financial liabilities	Total	Finance debt	Other financial liabilities	Total
Due within						
1 year	10,184	–	10,184	9,456	–	9,456
1 to 2 years	3,046	2,049	5,095	2,702	2,087	4,789
2 to 5 years	6,105	744	6,849	5,105	1,834	6,939
Thereafter	3,756	1,577	5,333	5,062	1,990	7,052
	23,091	4,370	27,461	22,325	5,911	28,236

25 Financial instruments *continued*

Interest rate and currency of financial liabilities

The interest rate and currency profile of the financial liabilities of the group, at 31 December, after taking into account the effect of interest rate swaps, currency swaps and forward contracts, is set out below.

	Fixed rate			Floating rate		Interest free		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Weighted average time until maturity Years	Amount $ million	Total $ million
								2004
Finance debt								
US dollar	7	11	707	3	21,789	–	–	22,496
Sterling	–	–	–	5	96	–	–	96
Other currencies	9	15	167	4	332	–	–	499
			874		22,217		–	23,091
Other financial liabilities								
US dollar	3	2	1,522	5	573	5	1,847	3,942
Sterling	–	–	–	–	–	4	193	193
Other currencies	4	4	15	2	46	4	174	235
			1,537		619		2,214	4,370
Total			2,411		22,836		2,214	27,461
								2003
Finance debt								
US dollar	8	14	578	2	20,991	–	–	21,569
Sterling	–	–	–	4	107	–	–	107
Other currencies	9	15	141	3	508	–	–	649
			719		21,606			22,325
Other financial liabilities								
US dollar	3	3	2,899	5	242	4	1,817	4,958
Sterling	–	–	–	–	–	5	267	267
Other currencies	5	4	303	–	–	6	383	686
			3,202		242		2,467	5,911
Total			3,921		21,848		2,467	28,236

		$ million
	2004	2003
Analysis of the above financial liabilities by balance sheet caption		
Creditors – amounts falling due within one year		
Finance debt	10,184	9,456
Creditors – amounts falling due after more than one year		
Finance debt	12,907	12,869
Other creditors	2,978	4,480
Provisions for liabilities and charges		
Other provisions	1,392	1,431
	27,461	28,236

The other financial liabilities comprise various accruals, sundry creditors and provisions relating to the group's normal commercial operations, with payment dates spread over a number of years.

The proportion of floating rate debt at 31 December 2004 was 96% of total finance debt outstanding. Aside from debt issued in the US municipal bond markets, interest rates on floating rate debt denominated in US dollars are linked principally to London Inter-Bank Offer Rate (LIBOR), while rates on debt in other currencies are based on local market equivalents. The group monitors interest rate risk using a process of sensitivity analysis. Assuming no changes to the finance debt and hedges described above, it is estimated that a change of 1% in the general level of interest rates on 1 January 2005 would change 2005 profit before tax by approximately $215 million.

25 Financial instruments *continued*

Interest rate swaps and futures are used by the group to modify the interest characteristics of its long-term finance debt from a fixed to a floating rate basis or vice versa. The following table indicates the types of instruments used and their weighted average interest rates as at 31 December.

	$ million except percentages	
	2004	2003
Receive fixed rate swaps – notional amount	8,182	7,432
Average receive fixed rate	3.1%	3.1%
Average pay floating rate	2.3%	1.1%

Currency exchange rate risk

The monetary assets and monetary liabilities of the group in currencies other than the functional currency of individual operating units are summarized below. These currency exposures arise from normal trading activities.

					$ million
	Net foreign currency monetary assets (liabilities)				
Functional currency	*US dollar*	*Sterling*	*Euro*	*Other currencies*	*Total*
					2004
US dollar	–	374	2	(942)	(566)
Sterling	314	–	380	66	760
Other currencies	(269)	(51)	(25)	(237)	(582)
Total	45	323	357	(1,113)	(388)
					2003
US dollar	–	191	(24)	39	206
Sterling	67	–	308	34	409
Other currencies	(1,148)	(25)	(27)	(131)	(1,331)
Total	(1,081)	166	257	(58)	(716)

In accordance with its policy for managing its foreign exchange rate risk, the group enters into various types of foreign exchange contracts, such as currency swaps, forwards and options. The fair values and carrying amounts of these derivatives are shown in the fair value table in Note 27.

Interest rate and currency of financial assets

The following table shows the interest rate and currency profile of the group's material financial assets at 31 December.

	Fixed rate			Floating rate		Interest free		
	Weighted average interest rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Weighted average time until maturity Years	Amount $ million	Total $ million
								2004
US dollar	10	11	72	4	186	5	252	510
Sterling	8	2	101	2	292	3	242	635
Other currencies	–	–	–	2	510	1	695	1,205
			173		988		1,189	2,350
								2003
US dollar	–	–	–	2	656	2	154	810
Sterling	8	2	91	3	907	2	257	1,255
Other currencies	3	2	19	1	189	1	1,866	2,074
			110		1,752		2,277	4,139

25 Financial instruments *continued*

	2004	2003
		$ million
Analysis of the above financial assets by balance sheet caption		
Fixed assets		
Investments	464	1,579
Current assets		
Debtors – amounts falling due after more than one year	402	428
Investments	328	185
Cash at bank and in hand	1,156	1,947
	2,350	4,139

The floating rate financial assets earn interest at various rates set principally with respect to LIBOR or the local market equivalent. Fixed asset investments included in the table above are held for the long term and have no maturity period. They are excluded from the calculation of weighted average time until maturity.

26 Derivative financial instruments

In the normal course of business, the group is a party to derivative financial instruments (derivatives) with off balance sheet risk, primarily to manage its exposure to fluctuations in foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt. The group also manages certain of its exposures to movements in oil, natural gas and power prices. In addition, the group trades derivatives in conjunction with these risk management activities.

Risk management

Gains and losses on derivatives used for risk management purposes are deferred and recognized in earnings or as adjustments to carrying amounts, as appropriate, when the underlying debt matures or the hedged transaction occurs. When an anticipated transaction is no longer likely to occur or finance debt is terminated before maturity, any deferred gain or loss that has arisen on the related derivative is recognized in the income statement, together with any gain or loss on the terminated item. Where such derivatives used for hedging purposes are terminated before the underlying debt matures or the hedged transaction occurs, the resulting gain or loss is recognized on a basis that matches the timing and accounting treatment of the underlying hedged item. The unrecognized and carried-forward gains and losses on derivatives used for hedging, and the movements therein, are shown in the following table.

	Unrecognized			Carried forward in the balance sheet		$ million
	Gains	Losses	Total	Gains	Losses	Total
Gains and losses at 1 January 2004	331	(130)	201	1,003	(425)	578
of which accounted for in income in 2004	98	(28)	70	438	(75)	363
Gains and losses at 31 December 2004	487	(408)	79	1,063	(364)	699
of which expected to be recognized in income in 2005	259	(267)	(8)	265	(77)	188
Gains and losses at 1 January 2003	526	(450)	76	352	(28)	324
of which accounted for in income in 2003	96	(51)	45	200	(14)	186
Gains and losses at 31 December 2003	331	(130)	201	1,003	(425)	578
of which expected to be recognized in income in 2004	98	(28)	70	438	(75)	363

Trading activities

The group maintains active trading positions in a variety of derivatives. This activity is undertaken in conjunction with risk management activities. Derivatives held for trading purposes are marked-to-market and any gain or loss recognized in the income statement. For traded derivatives, many positions have been neutralized, with trading initiatives being concluded by taking opposite positions to fix a gain or loss, thereby achieving a zero net market risk.

The following table shows the fair value at 31 December of derivatives and other financial instruments held for trading purposes. The fair values at the year end are not materially unrepresentative of the position throughout the year.

	2004		2003	$ million
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Interest rate contracts	–	–	–	–
Foreign exchange contracts	36	(90)	30	(54)
Oil price contracts	1,162	(1,177)	586	(667)
Natural gas price contracts	802	(624)	858	(711)
Power price contracts	82	(12)	548	(514)
	2,082	(1,903)	2,022	(1,946)

26 Derivative financial instruments *continued*

The group measures its market risk exposure, i.e. potential gain or loss in fair values, on its trading activity using value-at-risk techniques. These techniques are based on a variance/covariance model or a Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market values over a 24-hour period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures, and the history of one-day price movements over the previous 12 months, together with the correlation of these price movements. The potential movement in fair values is expressed to three standard deviations, which is equivalent to a 99.7% confidence level. This means that, in broad terms, one would expect to see an increase or a decrease in fair values greater than the value at risk on only one occasion per year if the portfolio were left unchanged.

The group calculates value at risk on all instruments that are held for trading purposes and that therefore give an exposure to market risk. The value-at-risk model takes account of derivative financial instruments such as interest rate forward and futures contracts, swap agreements, options and swaptions; foreign exchange forward and futures contracts, swap agreements and options; and oil, natural gas and power price futures, swap agreements and options. Financial assets and liabilities and physical crude oil and refined products that are treated as trading positions are also included in these calculations. The value-at-risk calculation for oil, natural gas and power price exposure also includes cash-settled commodity contracts such as forward contracts.

The following table shows values at risk for trading activities.

								$ million
				2004				2003
	High	Low	Average	Year end	High	Low	Average	Year end
Interest rate trading	1	–	–	–	1	–	–	–
Foreign exchange trading	4	1	1	1	4	–	2	1
Oil price trading	55	18	29	45	34	17	26	27
Natural gas price trading	23	6	13	10	29	4	16	18
Power price trading	10	1	4	4	13	–	4	6

The presentation of trading results shown in the table below includes certain activities of BP's trading units that involve the use of derivative financial instruments in conjunction with physical and paper trading of oil, natural gas and power. It is considered that a more comprehensive representation of the group's oil, natural gas and power price trading activities is given by aggregating the gain or loss on such derivatives together with the gain or loss arising from the physical and paper trades to which they relate, representing the net result of the trading portfolio.

		$ million
	2004	2003
	Net gain (loss)	Net gain (loss)
Interest rate trading	4	9
Foreign exchange trading	136	118
Oil price trading	1,371	825
Natural gas price trading	461	341
Power price trading	160	119
	2,132	1,412

27 Fair values of financial assets and liabilities

The estimated fair value of the group's financial instruments is shown in the table below. The table also shows the 'net carrying amount' of the financial asset or liability. This amount represents the net book value, i.e. market value when acquired or later marked-to-market. Interest rate contracts include futures contracts, swap agreements and options. Foreign exchange contracts include forward and futures contracts, swap agreements and options. Oil, natural gas and power price contracts include futures contracts, swap agreements and options and cash-settled commodity contracts such as forward contracts.

Short-term debtors and creditors that arise directly from the group's operations have been excluded from the disclosures contained in this note, as permitted by Financial Reporting Standard No. 13 'Derivatives and Other Financial Instruments: Disclosures'.

The fair value and carrying amounts of finance debt shown below exclude the effects of currency swaps, interest rate swaps and forward contracts (which are included for presentation in the balance sheet). Long-term borrowings in the table below include debt that matures in the year from 31 December 2004, whereas in the balance sheet long-term debt of current maturity is reported under amounts falling due within one year. Long-term borrowings also include US Industrial Revenue/Municipal Bonds classified on the balance sheet as repayable within one year.

$ million

	2004		2003	
Primary financial instruments	Net fair value asset (liability)	Net carrying amount asset (liability)	Net fair value asset (liability)	Net carrying amount asset (liability)
Fixed assets – investments	748	464	3,507	1,579
Current assets				
Debtors – amounts falling due after more than one year	402	402	428	428
Investments	328	328	185	185
Cash at bank and in hand	1,156	1,156	1,947	1,947
Finance debt				
Short-term borrowings	(5,003)	(5,003)	(5,059)	(5,059)
Long-term borrowings	(16,800)	(16,344)	(16,190)	(15,559)
Net obligations under finance leases	(2,608)	(2,579)	(2,479)	(2,452)
Creditors – amounts falling due after more than one year				
Other creditors	(2,978)	(2,978)	(4,480)	(4,480)
Provisions for liabilities and charges				
Other provisions	(1,392)	(1,392)	(1,431)	(1,431)
Derivative financial or commodity instruments				
Risk management				
Interest rate contracts	(73)	–	5	–
Foreign exchange contracts	1,084	835	941	745
Oil price contracts	7	7	(5)	(5)
Natural gas price contracts	35	35	(5)	(5)
Power price contracts	–	–	(10)	(10)
Trading				
Interest rate contracts	–	–	–	–
Foreign exchange contracts	(54)	(54)	(24)	(24)
Oil price contracts	(15)	(15)	(81)	(81)
Natural gas price contracts	178	178	147	147
Power price contracts	70	70	34	34

The following methods and assumptions were used by the group in estimating its fair value disclosures for its financial instruments:

Fixed assets – Investments The carrying amount reported in the balance sheet for unlisted fixed asset investments approximates their fair value. The fair value of listed fixed asset investments has been determined by reference to market prices.

Current assets – Debtors falling due after more than one year The fair value of other debtors due after one year is estimated not to be materially different from its carrying value.

Current assets – Investments and cash at bank and in hand The carrying amount reported in the balance sheet for unlisted current asset investments and cash at bank and in hand approximates their fair value. The fair value of listed current asset investments has been determined by reference to market prices.

Finance debt The carrying amount of the group's short-term borrowings, which mainly comprise commercial paper, bank loans and overdrafts, approximates their fair value. The fair value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses, based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

Creditors – Amounts falling due after more than one year – Other creditors Deferred consideration for the acquisition of our interest in TNK-BP is discounted to the present value of the future payments. The carrying value thus approximates the fair value. The remaining liabilities are predominantly interest-free. In view of their short maturities, the reported carrying amount is estimated to approximate the fair value.

Provisions for liabilities and charges – Other provisions Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure. The carrying amount of provisions thus approximates the fair value.

Derivative financial instruments and cash-settled commodity contracts The fair values of the group's interest rate and foreign exchange contracts are based on pricing models that take into account relevant market data. The fair values of the group's oil, natural gas and power price contracts (futures contracts, swap agreements, options and forward contracts) are based on market prices.

28 Finance debt

						$ million
			2004			2003
	Within 1 year	After 1 year	Total	Within 1 year	After 1 year	Total
Bank loans	250	457	707	205	253	458
Other loans	9,819	10,167	19,986	9,161	10,524	19,685
Total borrowings	10,069	10,624	20,693	9,366	10,777	20,143
Net obligations under finance leases	115	2,283	2,398	90	2,092	2,182
	10,184	12,907	23,091	9,456	12,869	22,325

Where finance debt is swapped into another currency, the finance debt is accounted in the swap currency and not in the original currency of denomination. Total finance debt includes an asset of $835 million ($745 million) for the carrying value of currency swaps and forward contracts.

Included within Other loans repayable within one year are US Industrial Revenue/Municipal Bonds of $2,487 million ($2,503 million) with maturity periods ranging up to 34 years. They are classified as repayable within one year, as required under UK GAAP, as the bondholders typically have the option to tender these bonds for repayment on interest reset dates. Any bonds that are tendered are usually remarketed and BP has not experienced any significant repurchases. BP considers these bonds to represent long-term funding when assessing the maturity profile of its finance debt.

At 31 December 2004, the group had substantial amounts of undrawn borrowing facilities available, including committed facilities of $4,500 million expiring in 2005 ($3,700 million expiring in 2004). These facilities are with a number of international banks and borrowings under them would be at pre-agreed rates. The group expects to renew the facilities on an annual basis. Certain of these facilities support the group's commercial paper programme.

At 31 December 2004, the group's share of third-party finance debt of joint ventures and associated undertakings was $2,821 million ($2,151 million) and $1,048 million ($922 million) respectively. These amounts are not reflected in the group's debt on the balance sheet.

						$ million
			2004			2003
Analysis of borrowings by year of repayment	Bank loans	Other loans	Total	Bank loans	Other loans	Total
Due after 10 years	1	773	774	–	721	721
Due within 10 years	29	1	30	–	17	17
9 years	20	5	25	–	337	337
8 years	22	365	387	–	291	291
7 years	28	286	314	–	–	–
6 years	36	99	135	7	1,700	1,707
5 years	33	1,691	1,724	7	938	945
4 years	29	1,510	1,539	8	1,291	1,299
3 years	251	2,431	2,682	193	2,593	2,786
2 years	8	3,006	3,014	38	2,636	2,674
	457	10,167	10,624	253	10,524	10,777
1 year	250	9,819	10,069	205	9,161	9,366
	707	19,986	20,693	458	19,685	20,143

Amounts included above repayable by instalments, part of which falls due after five years from 31 December, are as follows:

After 5 years	204	14
Within 5 years	76	82
	280	96

Interest rates on borrowings repayable wholly or partly more than five years from 31 December 2004 range from 1% to 12% with a weighted average of 4%. The weighted average interest rate on finance debt is 3%.

		$ million
Obligations under finance leases	2004	2003
Minimum future lease payments payable within		
1 year	152	127
2 to 5 years	1,060	979
Thereafter	3,540	3,528
	4,752	4,634
Less finance charges	2,354	2,452
Net obligations	2,398	2,182

29 Other creditors

$ million

	Group				Parent			
	2004		2003		2004		2003	
	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year	Within 1 year	After 1 year
Trade	28,340	–	20,858	–	–	–	–	–
Group undertakings	–	–	–	–	7,449	–	5,061	–
Joint ventures	137	–	126	–	–	–	–	–
Associated undertakings	364	5	322	4	–	–	–	–
Production taxes	517	1,520	421	1,544	–	–	–	–
Taxation on profits	4,131	–	3,441	–	–	–	–	–
Social security	122	–	96	–	57	–	46	–
Accruals and deferred income	9,569	1,000	6,411	1,321	7	76	22	50
Dividends	1,822	–	1,495	–	1,822	–	1,495	–
Other	9,339	1,980	7,958	3,161	173	–	176	–
	54,341	4,505	41,128	6,030	9,508	76	6,802	50

30 Other provisions

$ million

				Group	Parent
	Decom-missioning	Environ-mental	Other	Total	Other provisions
At 1 January 2004	4,720	2,298	1,797	8,815	216
Prior year adjustment – change in accounting policy	–	–	(216)	(216)	(216)
Restated	4,720	2,298	1,581	8,599	–
Exchange adjustments	213	21	25	259	–
New provisions	294	588	298	1,180	–
Write-back of unused provisions	–	(151)	(64)	(215)	–
Unwinding of discount	118	55	23	196	–
Change in discount rate	434	40	1	475	–
Utilized/deleted	(199)	(393)	(294)	(886)	–
At 31 December 2004	5,580	2,458	1,570	9,608	–

The group makes full provision for the future cost of decommissioning oil and natural gas production facilities and related pipelines on a discounted basis on the installation of those facilities. At 31 December 2004, the provision for the costs of decommissioning these production facilities and pipelines at the end of their economic lives was $5,580 million ($4,720 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2.5%). These costs are expected to be incurred over the next 30 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of incurring these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount reasonably determinable. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or closure of inactive sites. The provision for environmental liabilities at 31 December 2004 was $2,458 million ($2,298 million). The provision has been estimated using existing technology, at current prices and discounted using a real discount rate of 2.0% (2.5%). The majority of these costs are expected to be incurred over the next 10 years. The extent and cost of future remediation programmes are inherently difficult to estimate. They depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group's share of liability.

The group also holds provisions for expected rental shortfalls on surplus properties, litigation and sundry other liabilities. To the extent that these liabilities are not expected to be settled within the next three years, the provisions are discounted using either a nominal discount rate of 4.5% (4.5%) or a real discount rate of 2.0% (2.5%), as appropriate.

31 Pensions

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees' pensionable salary and length of service. Defined benefit plans may be externally funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

Contributions to funded defined benefit plans are based on advice from independent actuaries using actuarial methods, the objective of which is to provide adequate funds to meet pension obligations as they fall due. The pension plans in the UK and US are reviewed annually by the independent actuaries and subject to a formal actuarial valuation at least every three years. The date of the latest actuarial valuation for the UK and US plans was 1 January 2003 and 1 January 2004 respectively. The date of the most recent actuarial reviews was 31 December 2004.

During 2004, contributions of $249 million ($258 million) and $30 million ($2,189 million) were made to the UK plans and US plans respectively. In addition, contributions of $116 million ($86 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2005 is expected to be approximately $600 million.

31 Pensions *continued*

The pension assumptions for the principal plans are set out below. The assumptions used to evaluate accrued pension benefits at 31 December in any year are used to determine pension expense for the following year, that is, the assumptions at 31 December 2004 are used to determine the pension liabilities at that date and the pension cost for 2005. The assumptions for the parent company are the same as those shown for the UK.

%	UK			USA			Other		
	2004	2003	2002	2004	2003	2002	2004	2003	2002
Discount rate for plan liabilities	5.25	5.5	5.75	5.75	6.0	6.75	5.0	5.5	5.75
Rate of increase in salaries	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Rate of increase for pensions in payment	2.5	2.5	2.5	nil	nil	nil	2.5	2.5	2.5
Rate of increase in deferred pensions	2.5	2.5	2.5	nil	nil	nil	2.5	2.5	2.5
Inflation	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5

The assumed rate of investment return and discount rate have a significant effect on the amounts reported. A one-percentage-point change in these assumptions for the group's plans would have had the following effects:

$ million	One-percentage point	
	Increase	Decrease
Investment return		
Effect on pension expense in 2005	(312)	314
Discount rate		
Effect on pension expense in 2005	(87)	88
Effect on pension obligation at 31 December 2004	(4,508)	5,575

The expected long-term rates of return and market values of the various categories of asset held by the significant defined benefit plans at 31 December are set out below.

	Group						Parent		
	2004		2003		2002		2004	2003	2002
	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million	Market value $ million	Market value $ million	Market value $ million
UK plans									
Equities	7.5	17,329	7.5	14,642	7.5	10,815	16,263	13,815	10,186
Bonds	4.5	2,859	4.75	2,477	5.0	2,263	2,396	2,092	1,914
Property	6.5	1,660	6.5	1,336	6.5	1,352	1,645	1,325	1,341
Cash	4.0	459	4.0	769	4.0	708	402	618	691
	7.0	22,307	7.0	19,224	7.0	15,138	20,706	17,850	14,132
Present value of plan liabilities		20,399		17,766		14,822	18,613	16,288	13,635
Surplus in the plans		1,908		1,458		316	2,093	1,562	497
Deferred tax		(572)		(437)		(95)	(628)	(469)	(149)
At 31 December		1,336		1,021		221	1,465	1,093	348
US plans									
Equities	8.5	6,043	8.5	5,650	8.5	3,371			
Bonds	4.75	1,057	4.75	1,018	5.5	720			
Property	8.0	28	8.0	41	8.0	49			
Cash	3.0	55	3.5	148	3.5	66			
	8.0	7,183	8.0	6,857	8.0	4,206			
Present value of plan liabilities		7,826		7,709		6,765			
Deficit in the plans		(643)		(852)		(2,559)			
Deferred tax		231		307		921			
At 31 December		(412)		(545)		(1,638)			
Other plans									
Equities	8.0	933	7.5	686	7.5	515			
Bonds	4.25	857	4.75	737	5.0	672			
Property	5.25	114	6.5	129	6.5	101			
Cash	3.5	288	4.0	187	4.0	159			
	6.0	2,192	6.0	1,739	6.0	1,447			
Present value of plan liabilities		8,044		6,376		5,141			
Deficit in the plans		(5,852)		(4,637)		(3,694)			
Deferred tax		540		302		249			
At 31 December		(5,312)		(4,335)		(3,445)			

31 Pensions *continued*

$ million

	2004			2003			2002		
	Surplus	Deficit	Net	Surplus	Deficit	Net	Surplus	Deficit	Net
UK plans	1,465	(129)	1,336	1,093	(72)	1,021	348	(127)	221
US plans	–	(412)	(412)	–	(545)	(545)	–	(1,638)	(1,638)
Other plans	10	(5,322)	(5,312)	53	(4,388)	(4,335)	40	(3,485)	(3,445)
At 31 December	1,475	(5,863)	(4,388)	1,146	(5,005)	(3,859)	388	(5,250)	(4,862)

$ million

	Group								Parent	
	2004				2003				2004	2003
Analysis of the amount charged to operating profit	UK	USA	Other	Total	UK	USA	Other	Total		
Current service cost	363	215	118	696	290	177	116	583	341	261
Past service cost	5	–	38	43	–	14	–	14	5	–
Settlement, curtailment and special termination benefits	37	–	27	64	–	(11)	87	76	36	–
Payments to defined contribution plans	–	150	12	162	–	134	36	170	–	–
Total operating charge	405	365	195	965	290	314	239	843	382	261
Analysis of the amount credited (charged) to other finance income										
Expected return on pension plan assets	1,351	526	104	1,981	1,053	351	94	1,498	1,257	983
Interest on pension plan liabilities	(981)	(445)	(346)	(1,772)	(848)	(432)	(301)	(1,581)	(899)	(779)
Other finance income (expense)	370	81	(242)	209	205	(81)	(207)	(83)	358	204
Analysis of the amount recognized in the statement of total recognized gains and losses										
Actual return less expected return on pension plan assets	818	379	152	1,349	1,639	749	2	2,390	750	1,526
Experience gains and losses arising on plan liabilities	83	(22)	(562)	(501)	641	30	135	806	157	621
Change in assumptions underlying the present value of plan liabilities	(795)	(108)	(366)	(1,269)	(1,437)	(1,030)	(279)	(2,746)	(710)	(1,306)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	106	249	(776)	(421)	843	(251)	(142)	450	197	841
Movement in surplus (deficit) during the year										
Surplus (deficit) in schemes at 1 January	1,458	(852)	(4,637)	(4,031)	316	(2,559)	(3,694)	(5,937)	1,563	497
Movement in year										
Current service cost	(363)	(215)	(118)	(696)	(290)	(177)	(116)	(583)	(341)	(261)
Past service cost	(5)	–	(38)	(43)	–	(14)	–	(14)	(5)	–
Settlement, curtailment and special termination benefits	(37)	–	(27)	(64)	–	11	(87)	(76)	(36)	–
Acquisitions	–	–	(3)	(3)	–	–	1	1	–	–
Disposals	–	32	59	91	–	–	–	–	–	–
Other finance income (expense)	370	81	(242)	209	205	(81)	(207)	(83)	358	204
Actuarial gain (loss)	106	249	(776)	(421)	843	(251)	(142)	450	197	841
Employers' contributions – funded plans	249	30	116	395	258	2,189	86	2,533	214	142
Employers' contributions – unfunded plans	–	32	285	317	–	30	209	239	–	–
Exchange adjustments	130	–	(471)	(341)	126	–	(687)	(561)	142	140
Surplus (deficit) in plans at 31 December	1,908	(643)	(5,852)	(4,587)	1,458	(852)	(4,637)	(4,031)	2,092	1,563

31 Pensions *continued*

History of experience gains and losses	UK	USA	Other	Group Total	Parent
				2004	2004
Difference between the expected and actual return on plan assets					
Amount ($ million)	818	379	152	1,349	750
Percentage of plan assets	4%	5%	7%	4%	4%
Experience gains and losses on plan liabilities					
Amount ($ million)	83	(22)	(562)	(501)	157
Percentage of the present value of plan liabilities	0%	0%	(7)%	(1)%	1%
Total amount recognized in statement of total recognized gains and losses					
Amount ($ million)	106	249	(776)	(421)	197
Percentage of the present value of plan liabilities	1%	3%	(10)%	(1)%	1%
				2003	2003
Difference between the expected and actual return on plan assets					
Amount ($ million)	1,639	749	2	2,390	1,526
Percentage of plan assets	9%	11%	0%	9%	9%
Experience gains and losses on plan liabilities					
Amount ($ million)	641	30	135	806	621
Percentage of the present value of plan liabilities	4%	0%	2%	3%	4%
Total amount recognized in statement of total recognized gains and losses					
Amount ($ million)	843	(251)	(142)	450	841
Percentage of the present value of plan liabilities	5%	(3)%	(2)%	1%	5%
				2002	2002
Difference between the expected and actual return on plan assets					
Amount ($ million)	(3,874)	(1,305)	(137)	(5,316)	(3,655)
Percentage of plan assets	(26)%	(31)%	(9)%	(26)%	(26)%
Experience gains and losses on plan liabilities					
Amount ($ million)	212	(290)	90	12	230
Percentage of the present value of plan liabilities	1%	(4)%	2%	0%	2%
Total amount recognized in statement of total recognized gains and losses					
Amount ($ million)	(4,142)	(1,938)	(487)	(6,567)	(3,808)
Percentage of the present value of plan liabilities	(28)%	(29)%	(9)%	(25)%	(28)%

32 Other post-retirement benefits

Certain group companies in the US provide post-retirement healthcare and life insurance benefits to their retired employees and dependants. The entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service. The plans are funded to a limited extent. The cost of providing post-retirement benefits is assessed annually by independent actuaries using the projected unit method. The date of the latest actuarial valuation was 1 January 2004 and the date of the most recent actuarial review was 31 December 2004.

At 31 December 2004, the independent actuaries reassessed the obligation for post-retirement benefits at $3,676 million ($4,143 million). The discount rate used to assess the obligation at 31 December 2004 of the plans was 5.75% (6.0%).

Assumed future healthcare cost trend rate	2005	2006	2007	2008	2009 and subsequent years
Beneficiaries aged under 65	9%	8%	7%	6%	5%
Beneficiaries aged over 65	12%	10%	8%	7%	6%

The assumed healthcare cost trend rate has a significant effect on the amounts reported. A one-percentage-point change in the assumed healthcare cost trend rate would have had the following effects:

		$ million
	One-percentage point	
	Increase	Decrease
Effect on post-retirement benefit expense in 2005	39	(31)
Effect on post-retirement obligation at 31 December 2004	458	(373)

BP's post-retirement medical plans in the US provide prescription drug coverage for Medicare-eligible retirees. The group's obligation for other post-retirement benefits at 31 December 2004 reflects the effects of the recent Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to co-ordinate with the Medicare benefit. BP reflected the impact of the legislation by reducing its actuarially determined obligation for post-retirement benefits at 31 December 2004 and will reduce the net cost for post-retirement benefits in subsequent periods. The reduction in liability was reflected in the 2004 results as an actuarial gain (assumption change).

The expected long-term rates of return and market values of the various categories of assets held by the plans at 31 December are set out below.

		2004		2003		2002
	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million
US plans						
Equities	8.5	21	8.5	24	8.5	24
Bonds	4.75	9	4.75	9	5.5	9
	7.25	30	8.0	33	8.0	33
Present value of plan liabilities		3,676		4,143		4,326
Other post-retirement benefits liability before deferred tax		(3,646)		(4,110)		(4,293)
Deferred tax		1,520		1,480		1,545
At 31 December		(2,126)		(2,630)		(2,748)

32 Other post-retirement benefits *continued*

$ million	2004	2003
Analysis of the amount charged to operating profit		
Current service cost	61	54
Past service cost	(4)	14
Settlement, curtailment and special termination benefits	–	(669)
Total operating charge (income)	57	(601)
Analysis of the amount charged to other finance costs		
Expected return on plan assets	2	2
Interest on plan liabilities	(240)	(259)
Other finance expense	(238)	(257)
Analysis of the amount recognized in the statement of total recognized gains and losses		
Actual return less expected return on plan assets	–	2
Experience gains and losses arising on plan liabilities	33	67
Change in assumptions underlying the present value of plan liabilities	495	(443)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	528	(374)
Movement in deficit during the year		
Deficit in plans at 1 January	(4,110)	(4,293)
Movement in year		
Current service cost	(61)	(54)
Past service cost	4	(14)
Settlement, curtailment and special termination benefits	–	669
Disposals	18	–
Other finance expense	(238)	(257)
Actuarial gain (loss)	528	(374)
Employers' contributions	213	213
Exchange adjustments	–	–
Deficit in schemes at 31 December	(3,646)	(4,110)

History of experience gains and losses	2004	2003	2002
Difference between the expected and actual return on plan assets			
Amount ($ million)	–	2	(8)
Percentage of plan assets	0%	6%	(24)%
Experience gains and losses on plan liabilities			
Amount ($ million)	33	67	(89)
Percentage of the present value of plan liabilities	1%	2%	(2)%
Total amount recognized in statement of total recognized gains and losses			
Amount ($ million)	528	(374)	(1,262)
Percentage of the present value of plan liabilities	14%	(9)%	(29)%

33 Called up share capital

The company's authorized ordinary share capital remains unchanged at 36 billion shares of 25 cents each, amounting to $9 billion. In addition, the company has authorized preference share capital of 12,750,000 shares of £1 each ($21 million). During 2004, the number of ordinary shares in issue decreased by 596,632,202. The number of ordinary shares bought back for cancellation exceeded the number issued in connection with the deferred consideration for the TNK-BP transaction, for employee share schemes and in connection with the ARCO acquisition. Further details of movements in share capital are shown in Note 34.

The allotted, called up and fully paid share capital at 31 December was as follows:

		2004		2003
	Shares	$ million	Shares	$ million
Non-equity				
8% cumulative first preference shares of £1 each	7,232,838	12	7,232,838	12
9% cumulative second preference shares of £1 each	5,473,414	9	5,473,414	9
Equity				
Ordinary shares of 25 cents each	21,525,977,902	5,382	22,122,610,104	5,531
		5,403		5,552

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

34 Capital and reserves

$ million

Group	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Other reserves	Own shares	Profit and loss account	Total
At 1 January 2004	5,552	3,957	523	27,077	129	–	38,700	75,938
Prior year adjustment – change in accounting policy	–	–	–	–	–	(96)	(5,247)	(5,343)
Restated	5,552	3,957	523	27,077	129	(96)	33,453	70,595
Currency translation differences (net of tax)	–	–	–	–	–	(7)	2,143	2,136
Actuarial gain (net of tax)	–	–	–	–	–	–	203	203
Unrealized gain on acquisition of further investment in equity-accounted investments	–	–	–	–	–	–	94	94
Employee share schemes	16	311	–	–	–	–	–	327
ARCO	7	153	–	85	(85)	–	–	160
Issue of ordinary share capital for TNK-BP	35	1,215	–	–	–	–	–	1,250
Purchase of shares by ESOP trusts	–	–	–	–	–	(147)	–	(147)
Charge for long-term performance plans and employee share schemes	–	–	–	–	–	–	226	226
Release of shares by ESOP trusts	–	–	–	–	–	168	(168)	–
Repurchase of ordinary share capital	(207)	–	207	–	–	–	(7,548)	(7,548)
Profit for the year	–	–	–	–	–	–	15,731	15,731
Dividends	–	–	–	–	–	–	(6,371)	(6,371)
At 31 December 2004	5,403	5,636	730	27,162	44	(82)	37,763	76,656

34 Capital and reserves *continued*

$ million

Parent	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Other reserves	Own shares	Profit and loss account	Total
At 1 January 2004	5,552	3,957	523	26,360	129	–	40,370	76,911
Prior year adjustment – change in accounting policy	–	–	–	–	–	(96)	(2,045)	(2,141)
Restated	5,552	3,957	523	26,380	129	(96)	38,325	74,770
Currency translation differences (net of tax)	–	–	–	–	–	(7)	–	(7)
Actuarial gain (net of tax)	–	–	–	–	–	–	138	138
Employee share schemes	23	464	–	–	–	–	–	487
ARCO	–	–	–	85	(85)	–	–	–
Issue of ordinary share capital for TNK-BP	35	1,215	–	–	–	–	–	1,250
Purchase of shares by ESOP trusts	–	–	–	–	–	(147)	–	(147)
Charge for long-term performance plans and employee share schemes	–	–	–	–	–	–	208	208
Release of shares by ESOP trusts	–	–	–	–	–	168	(168)	–
Repurchase of ordinary share capital	(207)	–	207	–	–	–	(7,548)	(7,548)
Profit for the year	–	–	–	–	–	–	18,677	18,677
Dividends	–	–	–	–	–	–	(6,371)	(6,371)
At 31 December 2004	5,403	5,636	730	26,465	44	(82)	43,261	81,457

Employee share schemes
During the year, 62,224,092 ordinary shares were issued under the BP, Amoco and Burmah Castrol employee share schemes.

ARCO
29,288,178 ordinary shares were issued in respect of ARCO employee share option schemes.

Repurchase of ordinary share capital
The company purchased for cancellation 827,240,360 ordinary shares for a total consideration of $7,548 million.

As a consolidated income statement is presented, a separate income statement for the parent company is not required to be published.

The profit and loss account reserve includes the following amounts, the distribution of which is limited by statutory or other restrictions:

	2004	2003
	$ million	
Parent company	25,026	24,107
Subsidiary undertakings	2,927	2,115
Joint ventures and associated undertakings	441	566
	28,394	26,788

35 Reconciliation of movements in shareholders' interest

$ million

	Note	2004	2003
Profit for the year		15,731	10,482
Currency translation differences		2,344	3,673
Actuarial gain relating to pensions and other post-retirement benefits		107	76
Tax on currency translation differences		(208)	(37)
Tax on actuarial gain (loss) relating to pensions and other post-retirement benefits		96	(16)
Unrealized gain on acquisition of further investment in equity-accounted investments		94	–
Dividends	13	(6,371)	(5,753)
Issue of ordinary share capital for employee share schemes		487	173
Issue of ordinary share capital for TNK-BP		1,250	–
Purchase of shares by ESOP trusts		(147)	(63)
Charge for long-term performance plans and employee share schemes		226	225
Repurchase of ordinary share capital		(7,548)	(1,999)
Net increase in shareholders' interest		6,061	6,761
Shareholders' interest at 1 January		70,595	63,834
Shareholders' interest at 31 December		76,656	70,595

36 Group cash flow statement analysis

Reconciliation of historical cost profit before interest and tax to net cash inflow from operating activities	2004	2003
		$ million
Historical cost profit before interest and tax	25,242	17,954
Depreciation and amounts provided	12,583	10,940
Exploration expenditure written off	274	297
Net operating charge for pensions and other post-retirement benefits, less contributions	(67)	(2,913)
Share of profits of joint ventures and associated undertakings	(3,574)	(1,438)
Interest and other income	(325)	(341)
(Profit) loss on sale of fixed assets and businesses or termination of operations	(815)	(831)
Charge for provisions	671	782
Utilization of provisions	(781)	(716)
(Increase) decrease in stocks	(3,595)	(841)
(Increase) decrease in debtors	(10,920)	(3,042)
Increase (decrease) in creditors	9,861	1,847
Net cash inflow from operating activities	28,554	21,698

Financing	2004	2003
		$ million
Long-term borrowing	(2,675)	(4,322)
Repayments of long-term borrowing	2,204	3,560
Short-term borrowing	(3,335)	(4,706)
Repayments of short-term borrowing	3,375	4,708
	(431)	(760)
Issue of ordinary share capital for employee share schemes	(487)	(173)
Purchase of shares by ESOP trusts	147	63
Repurchase of ordinary share capital	7,548	1,999
Net cash outflow (inflow)	6,777	1,129

Management of liquid resources

Liquid resources comprise current asset investments, which are principally commercial paper issued by other companies. The net cash outflow from the management of liquid resources was $132 million ($41 million inflow).

Commercial paper

Net movements in commercial paper are included within short-term borrowings or repayment of short-term borrowings as appropriate.

								$ million
	2004				2003			
Movement in net debt	Finance debt	Cash	Current asset investments	Net debt	Finance debt	Cash	Current asset investments	Net debt
At 1 January	(22,325)	1,947	185	(20,193)	(22,008)	1,520	215	(20,273)
Exchange adjustments	(403)	80	11	(312)	(199)	110	11	(78)
Debt acquired	–	–	–	–	(15)	–	–	(15)
Net cash flow	(431)	(871)	132	(1,170)	(760)	317	(41)	(484)
Debt transferred to TNK-BP	–	–	–	–	93	–	–	93
Exchange of Exchangeable Bonds for Lukoil American Depositary Shares	–	–	–	–	420	–	–	420
Other movements	68	–	–	68	144	–	–	144
At 31 December	(23,091)	1,156	328	(21,607)	(22,325)	1,947	185	(20,193)

37 Employee share plans

Employee share options granted during the year[a] (options thousand)	2004	2003
Executive Directors' Incentive Plan	2,783	2,728
BP Share Option Plan	*71,750*	*78,109*
Savings-related schemes	5,861	23,922
	80,394	104,759

[a]The exercise prices for BP options granted during the year were £4.22/$7.73 (weighted average price) for Executive Directors' Incentive Plan (2,783,333 options); £4.38/$8.01 (weighted average price) for 71,750,436 options granted under the BP Share Option Plan; and £3.86/$7.06 (5,860,991 options) for savings-related and similar plans.

BP offers most of its employees the opportunity to acquire a shareholding in the company through savings-related and/or matching share plan arrangements. Such arrangements are now in place in more than 80 countries. BP also uses long-term performance plans *(see Note 38)* and the granting of share options as elements of remuneration for executive directors and senior employees.

During 2004, share options were granted to the executive directors under the Executive Directors' Incentive Plan (EDIP). For these options, the option exercise price was the market value (as determined in accordance with the plan rules) on the grant date. The options granted to executive directors reflect BP's performance in terms of total shareholder return, that is, share price increase with all dividends reinvested, relative to the FTSE Global 100 group of companies over the three years preceding the grant as well as the underlying health of the business and the competitive marketplace. Options have not been granted in any year unless the criteria for an award of shares under the share element of the EDIP *(see Note 38)* have been met. Options vest over three years (one-third each after one, two and three years respectively) and have a life of seven years after the grant.

Share options were also granted in 2004 under the BP Share Option Plan to certain categories of employees. Subject to certain vesting requirements, the options are exercisable between the third and 10th anniversaries of the date of grant. There are no performance conditions attaching to the options granted during the year.

Under the BP ShareSave Plan (a savings-related share option plan), employees save on a monthly basis over a three- or five-year period towards the purchase of shares at a price fixed when the option is granted. The option price is usually set at a 20% discount to the market price at the time of grant. The option must be exercised within six months of maturity of the savings contract; otherwise it lapses. The plan is run in the UK and a small number of other countries.

Under the BP ShareMatch Plan, BP matches employees' own contributions of shares, up to a predetermined limit. The shares are then held in trust for a defined minimum period. The plan is run in the UK and in over 70 other countries.

The group takes advantage of the exemption granted under Urgent Issues Task Force Abstract No. 17 (revised 2003) 'Employee Share Schemes', whereby no compensation expense need be recognized for the BP ShareSave Plan. BP does not recognize an expense in respect of share options granted to employees under the BP Share Option Plan. If the fair value of options granted in any particular year is estimated and this value amortized over the vesting period of the options, an indication of the cost of granting options to employees can be made. The fair value of each share option granted has been estimated using a Black Scholes option pricing model with the following assumptions:

	2004	2003
Risk-free interest rate	4.00%	3.5%
Expected volatility	22%	30%
Expected life in years	1 to 5	1 to 5
Expected dividend yield	3.75%	4.00%
Weighted average fair value of options granted ($)	1.40	1.44

The additional expense that would have been recognized in 2004 on this basis would be $79 million ($79 million) and the impact on earnings per share would be 1 cent (1 cent).

The company sponsors a number of savings plans covering most US employees. Under these plans, most employees may contribute up to 100% of their salary subject to certain regulatory limits. Most employees are eligible for a dollar-for-dollar company-matched contribution for the first 7% of eligible pay contributed on a before-tax or after-tax basis, or a combination of both. The precise arrangement may vary in certain business units. Plan participants may invest contributions in more than 200 investment options, including a fund comprised primarily of BP ADSs. The company's contributions generally vest over a period of three years (0% for years one and two and 100% after completion of three years). Company contributions to savings plans during the year were $138 million ($130 million).

An Employee Share Ownership Plan (ESOP) was established in 1997 to acquire BP shares to satisfy future requirements of employee share plans, principally the BP ShareMatch Plan. The ESOP holds the shares for participants during the retention period of the plan. The company provides funding to the ESOP. Until such time as the company's own shares held by the ESOP trust vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest *(see Notes 34 and 35)*. Other assets and liabilities of the ESOP are recognized as assets and liabilities of the company. The ESOP has waived its rights to dividends.

During 2004, the ESOP released 14,156,047 shares (16,892,853 shares) for the matching share plans. The cost of shares released for these plans has been charged in these accounts. At 31 December 2004, the ESOP held 2,682,860 shares (7,811,544 shares), which had a market value of $26 million ($63 million).

37 Employee share plans *continued*

Shares issued in respect of options exercised during the year (shares thousand)	2004	2003
Savings-related schemes	3,163	5,325
BP, Amoco and Burmah Castrol executive share option plans	59,061	27,564
	62,224	32,889

Options outstanding at 31 December	2004	2003
BP options (shares thousand)	470,264	461,886
Exercise period	2005-2014	2004-2013
Price	£2.04-£6.40	£1.86-£6.40
Price	$3.95-$9.97	$3.47-$9.97

Details of directors' individual participation in share schemes are given in the directors' remuneration report on pages 116-125.

38 Long-term performance plans

During 2004, the company operated two long-term performance plans: the Executive Directors' Incentive Plan (EDIP) for executive directors and the Long Term Performance Plan (LTPP) for senior employees. Executive directors participated in the LTPP prior to 2002 or to their appointment as an executive director, whichever was the later. Both plans are incentive schemes under which the company may award shares to participants or fund the purchase of shares for participants if long-term targets are met. Awards were made in 2004 in respect of the 2001-2003 LTPP. Further details of the plans are given in the directors' remuneration report on pages 116-125.

The costs of potential future awards for both the EDIP and LTPP are accrued over the three-year performance periods of each plan. The amount charged in 2004 was $89 million ($94 million). The value of awards under the 2001-2003 LTPP made in 2004 was $42 million (2000-2002 LTPP $35 million). Employees are able to defer the date of their potential award beyond the end of the performance period. The amount charged in respect of the increase in deferred awards after the expiry of the relevant performance periods was $23 million ($17 million).

Employee Share Ownership Plans (ESOPs) have been established to acquire BP shares to satisfy any awards made to participants under the EDIP and LTPP and then to hold them for the participants during the retention period of the plan. The company provides funding to the ESOPs. Until such time as the company's own shares held by the ESOP trusts vest unconditionally in employees, the amount paid for those shares is deducted in arriving at shareholders' interest *(see Notes 34 and 35)*. Other assets and liabilities of the ESOPs are recognized as assets and liabilities of the company. The ESOPs have waived their rights to dividends on shares held for future awards.

At 31 December 2004, the ESOPs held 5,938,359 shares (4,118,835 shares) for potential future awards, which had a market value of $58 million ($33 million).

39 Employee costs and numbers

Employee costs	2004	2003
Wages and salaries	7,922	7,142
Social security costs	667	622
Pension and other post-retirement benefit costs	1,051	582
	9,640	8,346

$ million

Number of employees at 31 December	2004	2003
Exploration and Production	15,650	15,150
Refining and Marketing[a]	67,250	66,150
Petrochemicals	12,400	15,950
Gas, Power and Renewables	4,050	3,750
Other businesses and corporate	3,550	2,700
	102,900	103,700

[a] Includes 27,950 (26,950) service station staff.

	2004					2003				
Average number of employees	UK	Rest of Europe	USA	Rest of World	Total	UK	Rest of Europe	USA	Rest of World	Total
Exploration and Production	2,900	650	4,900	6,950	15,400	3,200	750	5,000	6,900	15,850
Refining and Marketing	10,100	18,250	25,900	12,550	66,800	9,900	19,600	26,950	12,300	68,750
Petrochemicals	2,400	5,750	5,450	1,250	14,850	2,650	5,950	6,250	1,800	16,650
Gas, Power and Renewables	200	800	1,400	1,550	3,950	250	950	1,450	1,550	4,200
Other businesses and corporate	1,550	–	1,550	100	3,200	1,250	–	1,350	100	2,700
	17,150	25,450	39,200	22,400	104,200	17,250	27,250	41,000	22,650	108,150

40 Directors' remuneration

$ million

	2004	2003
Total for all directors		
Emoluments	19	17
Ex-gratia payments to executive directors retiring in the year	–	1
Gains made on the exercise of share options	3	1
Amounts awarded under incentive schemes	6	4

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus bonuses awarded for the year.

Pension contributions

Six executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2004.

Office facilities for former chairmen and deputy chairmen

It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information

Full details of individual directors' remuneration are given in the directors' remuneration report on pages 116-125.

41 Joint ventures and associated undertakings

The significant joint ventures and associated undertakings of the BP group at 31 December 2004 are shown in Note 46. The principal joint venture is the TNK-BP joint venture. Summarized financial information for the group's share of joint ventures is shown below.

$ million

	2004			2003		
	TNK-BP	Other	Total	TNK-BP	Other	Total
Turnover	7,839	1,951	9,790	1,864	1,610	3,474
Profit for the period before tax	2,320	455	2,775	475	360	835
Taxation	752	298	1,050	83	61	144
Profit for the period after tax	1,568	157	1,725	392	299	691
Fixed assets	9,955	4,556	14,511	8,389	3,558	11,947
Current assets	2,565	1,168	3,733	1,950	1,368	3,318
	12,520	5,724	18,244	10,339	4,926	15,265
Liabilities due within one year	1,959	686	2,645	1,575	752	2,327
Liabilities due after one year	1,851	1,820	3,671	1,350	1,434	2,784
	8,710	3,218	11,928	7,414	2,740	10,154
Minority shareholders' interest	542	–	542	365	–	365
	8,168	3,218	11,386	7,049	2,740	9,789

The joint venture TNK-BP was created on 29 August 2003. *(See Note 16 for further information.)* TNK-BP, in which BP holds a 50% interest, is an integrated oil company operating, inter alia, in Russia.

The preliminary fair values attributed to the assets and liabilities of TNK-BP in 2003 have been revised in 2004 as permitted by Financial Reporting Standard No. 7 'Fair Values in Acquisition Accounting'.

The results for TNK-BP for 2004 have been estimated. Any difference between the estimated and actual results for this period will be included in the results for 2005. The adjustment included in 2004 in respect of 2003 was a charge of $36 million.

BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America became subsidiary undertakings with effect from 2 November 2004. *(See Note 16 for further information.)*

Transactions between the significant joint ventures and associated undertakings and the group are summarized below.

Sales to joint ventures and associated undertakings $ million

		2004		2003	
	Product	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
Joint ventures					
BP Solvay Polyethylene Europe[a]	Chemicals feedstocks	230	–	259	33
Pan American Energy	Crude oil	118	4	171	5
Watson Cogeneration	Natural gas	214	10	73	6
Associated undertakings					
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	217	–	241	17
China American Petrochemical Co.	Chemicals feedstocks	385	81	240	67
Samsung Petrochemical Co.	Chemicals feedstocks	62	8	55	10

Purchases from joint ventures and associated undertakings $ million

		2004		2003	
	Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Joint ventures					
BP Solvay Polyethylene Europe[a]	Chemicals feedstocks	–	–	18	14
Pan American Energy	Crude oil	481	43	381	48
TNK-BP[b]	Crude oil and oil products	1,809	80	349	52
Watson Cogeneration	Electricity and steam	149	14	248	12
Associated undertakings					
Abu Dhabi Marine Areas	Crude oil	866	91	661	61
Abu Dhabi Petroleum Co.	Crude oil	1,547	145	1,122	118
BP Solvay Polyethylene North America[a]	Chemicals feedstocks	9	–	11	1
China American Petrochemical Co.	Petrochemicals	455	111	197	83
Samsung Petrochemical Co.	Chemicals feedstocks	290	17	187	38

[a]The 2004 BP Solvay Polyethylene Europe and BP Solvay Polyethylene North America sales and purchases shown above relate to the period to 2 November 2004.
[b]The 2003 TNK-BP purchases shown above relate to the period from 29 August to 31 December 2003.

42 Contingent liabilities

There were contingent liabilities at 31 December 2004 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities.

Approximately 200 lawsuits were filed in State and Federal Courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 47% interest (reduced during 2001 from 50% by a sale of 3% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages which it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Since 1987, Atlantic Richfield, a current subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed as against Atlantic Richfield. Atlantic Richfield (and in one case two of its affiliates) is named in these lawsuits as alleged successor to International Smelting & Refining which, along with a predecessor company, manufactured lead pigment during the period 1920-1946. Plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits (depending on plaintiff) seek various remedies, including: compensation to lead-poisoned children; cost to find and remove lead paint from buildings; medical monitoring and screening programmes; public warning and education on lead hazards; reimbursement of government healthcare costs and special education for lead-poisoned citizens; and punitive damages. No lawsuit against Atlantic Richfield has been settled or tried to conclusion. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences and it intends to defend such actions vigorously and thus the incurring of a liability by Atlantic Richfield is remote. Consequently, BP believes that the impact of these lawsuits on the group's results of operations, financial position or liquidity will not be material.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs could be significant and could be material to the group's results of operations in the period in which they are recognized, BP does not expect these costs to have a material effect on the group's financial position or liquidity.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premia with attendant transaction costs. The position is reviewed periodically.

The parent company has issued guarantees under which amounts outstanding at 31 December 2004 were $21,106 million ($20,903 million), including $21,050 million ($20,847 million) in respect of borrowings by its subsidiary undertakings and $56 million ($56 million) in respect of liabilities of other third parties. In addition, other group companies have issued guarantees under which amounts outstanding at 31 December 2004 were $1,281 million ($635 million) in respect of borrowings of joint ventures and associated undertakings and $650 million ($304 million) in respect of liabilities of other third parties.

43 Capital commitments

Authorized future capital expenditure by group companies for which contracts had been placed at 31 December 2004 amounted to $6,765 million ($6,420 million).

44 New accounting standards

Comparative information for 2003 has been restated to reflect the changes described below:

(a) New accounting standard for pensions and other post-retirement benefits

With effect from 1 January 2004, BP has adopted Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17). FRS 17 requires that financial statements reflect at fair value the assets and liabilities arising from an employer's retirement benefit obligations and any related funding. The operating costs of providing retirement benefits are recognized in the period in which they are earned, together with any related finance costs and changes in the value of related assets and liabilities. This contrasts with Statement of Standard Accounting Practice No. 24 'Accounting for Pension Costs', which required the cost of providing pensions to be recognized on a systematic and rational basis over the period during which the employer benefited from the employee's services. The difference between the amount charged in the income statement and the amount paid as contributions into the pension fund was shown as a prepayment or provision on the balance sheet.

This change in accounting policy has resulted in a prior year adjustment. Shareholders' interest at 1 January 2003 has been reduced by $5,601 million and the profit for the year ended 31 December 2003 increased by $215 million. Profit for the current year has been increased by approximately $301 million as a result of the change in accounting policy.

(b) Accounting for Employee Share Ownership Plans

With effect from 1 January 2004, BP has adopted Urgent Issues Task Force Abstract No. 38 'Accounting for Employee Share Ownership Plan (ESOP) Trusts'. This abstract requires that BP shares held by the group for the purposes of Employee Share Ownership Plans (ESOPs) are deducted from equity on the balance sheet. Such shares were previously classified as fixed asset investments. In addition, accruals for awards under the Long Term Performance Plan have also been included in reserves.

This change in accounting policy has resulted in a prior year adjustment. Shareholders' interest at 1 January 2003 has been increased by $26 million. The impact of the change in accounting policy on profit for the years ended 31 December 2003 and 2004 is not significant.

		$ million
Group income statement for the year ended 31 December 2003	Restated	Reported
Turnover	236,045	236,045
Less: Joint ventures	3,474	3,474
Group turnover	232,571	232,571
Replacement cost of sales	201,347	202,041
Production taxes	1,723	1,723
Gross profit	29,501	28,807
Distribution and administration expenses	14,072	14,072
Exploration expense	542	542
	14,887	14,193
Other income	786	786
Group replacement cost operating profit	15,673	14,979
Share of profits of joint ventures	923	923
Share of profits of associated undertakings	511	511
Total replacement cost operating profit	17,107	16,413
Profit (loss) on sale of businesses or termination of operations	(28)	(28)
Profit (loss) on sale of fixed assets	859	859
Replacement cost profit before interest and tax	17,938	17,244
Stock holding gains (losses)	16	16
Historical cost profit before interest and tax	17,954	17,260
Interest expense	644	851
Other finance expense	547	–
Profit before taxation	16,763	16,409
Taxation	6,111	5,972
Profit after taxation	10,652	10,437
Minority shareholders' interest	170	170
Profit for the year	10,482	10,267
Distribution to shareholders	5,753	5,753
Retained profit for the year	4,729	4,514
Earnings per ordinary share – cents		
Basic	47.27	46.30
Diluted	46.83	45.87

44 New accounting standards *continued*

Group balance sheet at 31 December 2003	Restated	Reported
	$ million	
Fixed assets		
Intangible assets	13,642	13,642
Tangible assets	91,911	91,911
Investments	17,458	17,554
	123,011	123,107
Current assets	47,651	54,465
Creditors – amounts falling due within one year	50,584	50,584
Net current liabilities	(2,933)	3,881
Total assets less current liabilities	120,078	126,988
Creditors – amounts falling due after more than one year	18,899	18,959
Provisions for liabilities and charges		
Deferred taxation	14,371	15,273
Other provisions	8,599	15,693
Net assets excluding pension and other post-retirement benefit balances	78,209	77,063
Defined benefit pension plan surplus	1,146	–
Defined benefit pension plan deficits	(5,005)	–
Other post-retirement benefit plan deficits	(2,630)	–
Net assets	71,720	77,063
Minority shareholders' interest	1,125	1,125
BP shareholders' interest	70,595	75,938

Statement of total recognized gains and losses for the year ended 31 December 2003	Restated	Reported
	$ million	
Profit for the year	10,482	10,267
Currency translation differences (net of tax)	3,636	3,841
Actuarial gain (net of tax)	60	–
Total recognized gains and losses	14,178	14,108

Group cash flow statement for the year ended 31 December 2003	Restated	Reported
	$ million	
Net cash inflow from operating activities	21,698	21,698
Dividends from joint ventures	131	131
Dividends from associated undertakings	417	417
Net cash outflow from servicing of finance and returns on investments	(711)	(711)
Tax paid	(4,804)	(4,804)
Net cash outflow for capital expenditure and financial investment	(6,124)	(6,187)
Net cash (outflow) inflow from acquisitions and disposals	(3,548)	(3,548)
Equity dividends paid	(5,654)	(5,654)
Net cash inflow (outflow) before financing	1,405	1,342
Financing	1,129	1,066
Management of liquid resources	(41)	(41)
Increase (decrease) in cash	317	317
	1,405	1,342

44 New accounting standards *continued*

$ million

Reconciliation of historical cost profit before interest and tax to net cash inflow from operating activities	*Restated*	*Reported*
Historical cost profit before interest and tax	17,954	17,260
Depreciation and amounts provided	10,940	10,940
Exploration expenditure written off	297	297
Net operating charge for pensions and other post-retirement benefits, less contributions	(2,913)	-
Share of profits of joint ventures and associated undertakings	(1,438)	(1,438)
Interest and other income	(341)	(341)
(Profit) loss on sale of fixed assets and businesses	(831)	(831)
Charge for provisions	782	1,734
Utilization of provisions	(716)	(1,204)
(Increase) decrease in stocks	(841)	(841)
(Increase) decrease in debtors	(3,042)	(5,628)
Increase (decrease) in creditors	1,847	1,750
Net cash inflow from operating activities	21,698	21,698

45 Transfer of natural gas liquids activities

With effect from 1 January 2004, natural gas liquids activities were transferred from Exploration and Production to Gas, Power and Renewables. The adjustments between these two segments for 2003 are set out below.

	$ million
Group replacement cost operating profit	106
Share of profits of joint ventures	–
Share of profits of associated undertakings	–
Total replacement cost operating profit	*106*
Exceptional items	–
Replacement cost profit before interest and tax	106
Stock holding gains (losses)	–
Historical cost profit before interest and tax	106
Capital expenditure and acquisitions	82
Operating capital employed	389
Tangible fixed assets	289

Number of employees	
Year end	200
Average	200

46 Subsidiary and associated undertakings and joint ventures

The more important subsidiary and associated undertakings and joint ventures of the group at 31 December 2004 and the group percentage of ordinary share capital or joint venture interest (to nearest whole number) are set out below. The principal country of operation is generally indicated by the company's country of incorporation or by its name. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiary and associated undertakings and joint ventures will be attached to the parent company's annual return made to the Registrar of Companies. Advantage has been taken of the exemption conferred by regulation 7 of The Partnerships and Unlimited Companies (Accounts) Regulations 1993 from the requirements to deliver to the Registrar of Companies and publish the annual accounts of the CaTO Finance V Limited Partnership.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Chemicals Investments	100	England	Petrochemicals
*BP Exploration Op. Co.	100	England	Exploration and production
*BP Global Investments	100	England	Investment holding
*BP International	100	England	Integrated oil operations
*BP Oil International	100	England	Integrated oil operations
*BP Shipping	100	England	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England	Exploration and production
Australia			
BP Australia	100	Australia	Integrated oil operations
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
Azerbaijan			
Amoco Caspian Sea Petroleum	100	British Virgin Islands	Exploration and production
BP Exploration (Caspian Sea)	100	England	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Co.	100	US	Exploration and production
BP Egypt Gas Co.	100	US	Exploration and production
France			
BP France	100	France	Refining and marketing and petrochemicals
Germany			
Deutsche BP	100	Germany	Refining and marketing and petrochemicals
Veba Oil	100	Germany	Refining and marketing and petrochemicals
Netherlands			
BP Capital	100	Netherlands	Finance
BP Nederland	100	Netherlands	Refining and marketing
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad			
BP Trinidad (LNG)	100	Netherlands	Exploration and production
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England	Finance
BP Chemicals	100	England	Petrochemicals
BP Oil UK	100	England	Refining and marketing
Britoil	100	Scotland	Exploration and production
Jupiter Insurance	100	Guernsey	Insurance
US			
Atlantic Richfield Co.			
*BP America			
BP America Production Company			
BP Amoco Chemical Company			
BP Company North America	100	US	Exploration and production, gas, power and renewables, refining and marketing, pipelines and petrochemicals
BP Corporation North America			
BP Products North America			
BP West Coast Products			
Standard Oil Co.			
BP Capital Markets America			Finance

Associated undertakings	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Marine Areas	37	England	Crude oil production
Abu Dhabi Petroleum Co.	24	England	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Co.	30	Cayman Islands	Pipelines
Korea			
Samsung Petrochemical Co.	47	England	Petrochemicals
Taiwan			
China American Petrochemical Co.	61	Taiwan	Petrochemicals

Joint ventures	%	Country of incorporation or registration	Principal activities
CaTO Finance V Limited Partnership	50	England	Finance
Lukarco	46	Netherlands	Exploration and production, pipelines
Pan American Energy	60	US	Exploration and production
Shanghai Secco Petrochemical Co.	50	China	Petrochemicals
TNK-BP	50	British Virgin Islands	Integrated oil operations
Unimar LLC	50	US	Exploration and production
Watson Cogeneration	51	US	Power generation

47 Oil and natural gas exploration and production activities[a]

$ million

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	2004 Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	27,540	4,691	43,518	10,450	2,892	10,401	–	3,834	103,326
Unproved properties	271	154	1,265	411	1,121	476	107	96	3,901
	27,811	4,845	44,783	10,861	4,013	10,877	107	3,930	107,227
Accumulated depreciation	17,637	2,787	19,783	5,532	1,347	5,559	–	1,011	53,656
Net capitalized costs	10,174	2,058	25,000	5,329	2,666	5,318	107	2,919	53,571

The group's share of joint ventures' and associated undertakings' net capitalized costs at 31 December 2004 was $12,077 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved	–	–	–	–	–	–	–	–	–
Unproved	2	–	58	5	–	13	–	–	78
	2	–	58	5	–	13	–	–	78
Exploration and appraisal costs[b]	51	17	422	199	85	142	113	9	1,038
Development costs	679	262	3,248	527	88	1,460	–	1,007	7,271
Total costs	732	279	3,728	731	173	1,615	113	1,016	8,387

The group's share of joint ventures' and associated undertakings' costs incurred in 2004 was $1,435 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Results of operations for the year ended 31 December									
Turnover[c]									
Third parties	3,458	626	1,735	1,785	989	524	5	467	9,589
Sales between businesses	2,423	609	11,603	2,547	519	1,407	–	2,847	21,955
	5,881	1,235	13,338	4,332	1,508	1,931	5	3,314	31,544
Exploration expenditure	26	25	361	141	14	45	17	8	637
Production costs	873	117	1,428	535	142	323	–	131	3,549
Production taxes	273	30	477	239	45	–	–	1,023	2,087
Other costs (income)[d]	(211)	38	1,884	458	96	122	(3)	1,380	3,764
Depreciation	1,524	172	2,673	797	174	347	–	121	5,808
	2,485	382	6,823	2,170	471	837	14	2,663	15,845
Profit before taxation[e]	3,396	853	6,515	2,162	1,037	1,094	(9)	651	15,699
Allocable taxes	1,288	534	2,290	870	104	441	2	151	5,680
Results of operations	2,108	319	4,225	1,292	933	653	(11)	500	10,019

The group's share of joint ventures' and associated undertakings' results of operations in 2004 was a profit of $1,908 million after deducting a tax charge of $1,078 million.

[a] This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group's share of joint ventures' and associated undertakings' activities is excluded from the tables and included in the footnotes, with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above. Profits (losses) on sale of fixed assets and businesses or termination of operations relating to the oil and natural gas exploration and production activities, which have been accounted as exceptional items, are also excluded.
[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs which are charged to income as incurred.
[c] Turnover represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.
[d] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.
[e] The exploration and production total replacement cost operating profit comprises:

$ million

	2004
Exploration and production activities	
Group (as above)	15,699
Joint ventures and associated undertakings	2,986
Mid-stream activities	(317)
Total replacement cost operating profit	18,368

47 Oil and natural gas exploration and production activities[a] *continued*

$ million

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	2003 Total
Capitalized costs at 31 December									
Gross capitalized costs									
Proved properties	25,212	4,506	43,480	10,404	3,905	9,751	1	3,260	100,519
Unproved properties	266	211	1,127	661	1,642	506	37	54	4,504
	25,478	4,717	44,607	11,065	5,547	10,257	38	3,314	105,023
Accumulated depreciation	15,346	2,912	19,807	5,067	1,890	5,516	32	1,218	51,788
Net capitalized costs	10,132	1,805	24,800	5,998	3,657	4,741	6	2,096	53,235

The group's share of joint ventures' and associated undertakings' net capitalized costs at 31 December 2003 was $10,232 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	2003 Total
Costs incurred for the year ended 31 December									
Acquisition of properties									
Proved	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–
Exploration and appraisal costs[b]	20	69	290	119	57	205	26	40	826
Development costs	740	236	3,474	512	42	1,614	–	917	7,535
Total costs	760	305	3,764	631	99	1,819	26	957	8,361

The group's share of joint ventures' and associated undertakings' costs incurred in 2003 was $6,282 million.

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	2003 Total
Results of operations for the year ended 31 December									
Turnover[c]									
Third parties	2,257	441	1,491	1,222	421	444	–	777	7,053
Sales between businesses	2,901	568	10,930	2,684	925	974	–	1,707	20,689
	5,158	1,009	12,421	3,906	1,346	1,418	–	2,484	27,742
Exploration expenditure	17	37	204	164	15	32	21	52	542
Production costs	800	113	1,262	463	166	241	–	135	3,180
Production taxes	233	14	439	189	40	–	–	742	1,657
Other costs (income)[d]	(151)	57	2,019	447	160	38	30	946	3,546
Depreciation	1,830	169	3,384	560	445	222	–	136	6,746
	2,729	390	7,308	1,823	826	533	51	2,011	15,671
Profit before taxation[e]	2,429	619	5,113	2,083	520	885	(51)	473	12,071
Allocable taxes	1,060	360	2,130	881	97	342	(12)	158	5,016
Results of operations	1,369	259	2,983	1,202	423	543	(39)	315	7,055

The group's share of joint ventures' and associated undertakings' results of operations in 2003 was a profit of $851 million after deducting a tax charge of $171 million.

[a] This note relates to the requirements contained within the UK Statement of Recommended Practice 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities'. Mid-stream activities of natural gas gathering and distribution and the operation of the main pipelines and tankers are excluded. The main mid-stream activities are the Alaskan transportation facilities, the Forties Pipeline system and the Central Area Transmission System. The group's share of joint ventures' and associated undertakings' activities is excluded from the tables and included in the footnotes, with the exception of the Abu Dhabi operations, which are included in the income and expenditure items above. Profits (losses) on sale of fixed assets and businesses or termination of operations relating to the oil and natural gas exploration and production activities, which have been accounted as exceptional items, are also excluded.

[b] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible fixed assets, and geological and geophysical exploration costs which are charged to income as incurred.

[c] Turnover represents proceeds from the sale of production and other crude oil and gas, including royalty oil sold on behalf of others where royalty is payable in cash.

[d] Includes the value of royalty oil sold on behalf of others where royalty is payable in cash, property taxes and other government take.

[e] The exploration and production total replacement cost operating profit comprises:

$ million

	2003
Exploration and production activities	
Group (as above)	12,071
Joint ventures and associated undertakings	1,022
Mid-stream activities	660
Total replacement cost operating profit	13,753

Supplementary information on oil and natural gas quantities

BP reserves governance

BP manages its hydrocarbon resources in three major categories: prospect inventory, non-proved reserves and proved reserves. When a discovery is made, volumes transfer from the prospect inventory to the non-proved reserve category. The reserves move through various non-proved reserves sub-categories as their technical and commercial maturity increases through appraisal activity. Reserves in a field will only be categorized as proved when all the criteria for attribution of proved status have been met, including an internally imposed requirement for project sanction, or for sanction expected within six months, or as part of a rolling drilling programme included within our business planning process. Internal approval and final investment decision are what we refer to as project sanction.

At the point of sanction, all booked reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. The first PD bookings will occur at the point of first oil or gas production. Major development projects typically take one to four years from the time of initial booking to the start of production. Adjustments may be made to booked reserves owing to production, reservoir performance, commercial factors, acquisition and divestment activity and additional reservoir development activity.

BP has an internal process to control the quality of reserve bookings that forms part of a holistic and integrated system of internal control. BP's process to manage reserve bookings has been centrally controlled for over 15 years and it currently has several key elements.

The first element is the accountabilities of certain officers of the company, which ensure that there is clear responsibility for review and, where appropriate, endorsement of changes to reserves bookings; that the review is independent of the operating business unit for the integrity and accuracy of the reserve estimates; and that there are effective controls in the reserve approval process and verification that the group's reserve estimates and the related financial impacts are reported in a timely manner.

The second element is the capital allocation processes whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group's business plan. A formal review process exists to review that both technical and commercial criteria are met prior to the commitment of capital to projects.

The third element is internal audit, whose role includes systematically examining the effectiveness of the group's financial controls designed to assure the reliability of reporting and safeguarding of assets and examining the group's compliance with laws, regulations and internal standards.

The fourth element is a quarterly due diligence review, which is separate and independent from the operating business units, of reserves associated with properties where technical, operational or commercial issues have arisen.

The fifth element is the established criteria whereby reserves above certain thresholds require central authorization. Furthermore, the volumes booked under these authorization levels are reviewed on a periodic basis. The frequency of review is determined according to field size and ensures that more than 70% of the BP reserves base undergoes central review every two years and more than 80% is reviewed every four years.

Reserves reporting

Our proved reserves are associated with both concessions (tax and royalty arrangements) and production-sharing agreements (PSAs). In a concession, the consortium of which we are a part is entitled to the reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to recover volumes that equate to costs incurred to develop and produce the reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves. Twenty-one per cent of our proved reserves are associated with PSAs. The main countries in which we operate under PSA arrangements are Algeria, Angola, Azerbaijan, Egypt, Indonesia and Vietnam.

As a UK-registered company reporting under UK GAAP, BP estimates its proved reserves under UK accounting rules for oil and gas companies contained in the Statement of Recommended Practice, 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP). In estimating its reserves under UK SORP, BP uses long-term planning prices; these are the long-term price assumptions on which the group makes decisions to invest in the development of a field. Using planning prices for estimating proved reserves removes the impact of the volatility inherent in using year-end spot prices on our reserve base and on cash flow expectations over the long term. The group's planning prices for estimating reserves through the end of 2004 were $20 per barrel for oil and $3.50 per mmBtu for natural gas.

In determining 'reasonable certainty' for UK SORP purposes, BP applies a number of additional internally imposed assessment principles, such as the requirement for internal approval and final investment decision (which we refer to as project sanction), or for such project sanction within six months and, for additional reserves in existing fields, the requirement that the reserves be included in the business plan and scheduled for development within three years.

On the basis of UK SORP, our total proved reserves for subsidiaries and equity-accounted entities at the end of 2004 increased to 18,583 mmboe, representing a proved reserve replacement ratio (RRR) before acquisitions and divestments of 110%, versus 109% in 2003. Our principal equity-accounted entity is TNK-BP. For subsidiaries only, the RRR is 106% and, for equity-accounted entities only, the RRR is 118%. The proved reserve replacement ratio (also known as the production replacement ratio) is the extent to which production is replaced by proved reserve additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, extensions, discoveries and other additions, excluding the impact of acquisitions and divestments. Natural gas is converted to oil equivalent at 5.8 billion cubic feet equals 1 million barrels. By their nature, there is always some risk involved in the ultimate development and production of reserves, including but not limited to final regulatory approval, the installation of new or additional infrastructure as well as changes in oil and gas prices and the continued availability of additional development capital. The estimated proved oil and natural gas reserves on this basis are shown on pages 89-90.

The US Securities and Exchange Commission (SEC) rules for estimating reserves are different in certain respects from SORP; in particular, the SEC requires the use of year-end prices.

At 31 December 2004, the marker price for Brent crude was $40.24 per barrel and for Henry Hub gas it was $6.01 per thousand cubic feet.

Applying higher year-end prices to reserve estimates and assuming they apply to the end-of-field life has the effect of increasing proved reserves associated with concessions (tax and royalty arrangements) for which additional development opportunities become economic at higher prices or where higher prices make it more economic to extend the life of a field. On the other hand, applying higher year-end prices to reserves in fields subject to PSAs has the effect of decreasing proved reserves from those fields because higher prices result in lower volume entitlements.

The company's proved reserves estimates on an SEC basis for the year ended 31 December 2004 reflect year-end prices and some adjustments that have been made vis-à-vis individual asset reserve estimates based on different applications of certain SEC interpretations of SEC regulations relating to the use of technology (mainly seismic) to estimate reserves in the reservoir away from wellbores and the reporting of fuel gas (i.e. gas used for fuel in operations on the lease) within proved reserves. On an aggregate basis, the net impact of these changes, comprising some reductions and some additions, is a decrease of 286 mmboe, resulting in total proved reserves of 18,297 mmboe (including equity-accounted entities) compared with our reserves under UK SORP. Excluding equity-accounted entities, our proved reserves on an SEC basis were 14,625 mmboe.

The total net movement in subsidiaries and equity-accounted entities comprises a decrease of 452 mmboe as a result of using the year-end price, offset by a net increase of 166 mmboe in respect of fuel gas and technology interpretations.

On an SEC basis, our total proved reserves for subsidiaries and equity-accounted entities at the end of 2004 decreased by 64 mmboe from 18,361 to 18,297 mmboe, representing a proved reserve replacement ratio (RRR) before acquisitions and divestments of 89% versus 111% in 2003. For subsidiaries only, the RRR is 78% and, for equity-accounted entities only, the RRR is 114%.

We have included certain reserve replacement ratios that are calculated using proved reserves attributed to equity-accounted entities as well as consolidated entities and which exclude acquisitions and divestments. SEC staff guidance states that such measures should not include both proved reserve additions attributable to consolidated entities and equity-accounted entities and should be based on beginning and ending proved reserve quantities as disclosed in the Annual Report on Form 20-F. On this basis our RRR would be 64% (39% for 2003).

The estimated proved oil and natural gas reserves prepared on an SEC basis are shown on pages 91-92.

Movements in estimated net proved reserves on a UK GAAP/SORP basis

2004

Crude oil[a] million barrels

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiary									
At 1 January 2004									
Developed	678	231	1,885	378	83	206	–	115	3,576
Undeveloped	216	87	1,353	366	83	967	–	801	3,873
	894	318	3,238	744	166	1,173	–	916	7,449
Changes attributable to									
Revisions of previous estimates	(97)	32	63	(111)	5	38	–	194	124
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	22	–	74	5	8	48	–	212	369
Improved recovery	57	4	55	31	–	6	–	3	156
Production[b]	(121)	(28)	(217)	(63)	(17)	(48)	–	(21)	(515)
Sales of reserves-in-place	–	–	(17)	(10)	(6)	–	–	–	(33)
	(139)	8	(42)	(148)	(10)	44	–	388	101
At 31 December 2004[c]									
Developed	548	217	1,938	296	70	275	–	79	3,423
Undeveloped	207	109	1,258	300	86	942	–	1,225	4,127
	755	326	3,196	596	156	1,217	–	1,304	7,550
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	–	–	–	206	1	–	1,384	705	2,296
Undeveloped	–	–	–	134	–	–	410	27	571
	–	–	–	340	1	–	1,794	732	2,867
Changes attributable to									
Revisions of previous estimates	–	–	–	(4)	–	–	382	15	393
Purchases of reserves-in-place	–	–	–	–	–	–	252	–	252
Extensions, discoveries and other additions	–	–	–	2	–	–	–	–	2
Improved recovery	–	–	–	17	–	–	37	–	54
Production	–	–	–	(25)	–	–	(304)	(55)	(384)
Sales of reserves-in-place	–	–	–	–	–	–	(4)	–	(4)
	–	–	–	(10)	–	–	363	(40)	313
At 31 December 2004[d]									
Developed	–	–	–	204	1	–	1,863	593	2,661
Undeveloped	–	–	–	126	–	–	294	99	519
	–	–	–	330	1	–	2,157	692	3,180
Total group and BP share of equity-accounted entities	755	326	3,196	926	157	1,217	2,157	1,996	10,730

[a]Crude oil includes natural gas liquids (NGLs) and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b]Excludes NGLs from processing plants in which an interest is held of 67 thousand barrels a day.
[c]Includes 39 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 127 million barrels of crude oil in respect of the 5.9% minority interest in TNK-BP.

Movements in estimated net proved reserves on a UK GAAP/SORP basis *continued*

2004

Natural gas[a]

billion cubic feet

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiary									
At 1 January 2004									
Developed	2,673	214	11,290	4,087	1,923	651	–	235	21,073
Undeveloped	817	1,211	2,547	12,484	2,988	2,028	–	828	22,903
	3,490	1,425	13,837	16,571	4,911	2,679	–	1,063	43,976
Changes attributable to									
Revisions of previous estimates	(226)	16	(791)	(1,889)	(2)	(9)	–	338	(2,563)
Purchases of reserves-in-place	–	–	3	2	–	–	–	–	5
Extensions, discoveries and other additions	31	–	140	991	2,478	233	–	3	3,876
Improved recovery	134	4	870	75	–	29	–	38	1,150
Production	(427)	(46)	(1,097)[b]	(854)	(284)	(98)	–	(73)	(2,879)
Sales of reserves-in-place	–	–	(202)	(91)	(247)	(103)	–	–	(643)
	(488)	(26)	(1,077)	(1,766)	1,945	52	–	306	(1,054)
At 31 December 2004[c]									
Developed	2,079	216	10,207	3,981	1,578	1,054	–	257	19,372
Undeveloped	923	1,183	2,553	10,824	5,278	1,677	–	1,112	23,550
	3,002	1,399	12,760	14,805	6,856	2,731	–	1,369	42,922
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	–	–	–	1,437	130	–	–	58	1,625
Undeveloped	–	–	–	823	77	–	–	28	928
	–	–	–	2,260	207	–	–	86	2,553
Changes attributable to									
Revisions of previous estimates	–	–	–	68	(13)	–	319	–	374
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	–	–	–	–	–	–
Improved recovery	–	–	–	23	–	–	–	–	23
Production	–	–	–	(129)	(22)	–	(168)	(3)	(322)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	(38)	(35)	–	151	(3)	75
At 31 December 2004[d]									
Developed	–	–	–	1,318	103	–	151	60	1,632
Undeveloped	–	–	–	904	69	–	–	23	996
	–	–	–	2,222	172	–	151	83	2,628
Total group and BP share of equity-accounted entities	3,002	1,399	12,760	17,027	7,028	2,731	151	1,452	45,550

[a]Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b]Includes 76 billion cubic feet of natural gas consumed in operations.
[c]Includes 4,117 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 9 billion cubic feet of natural gas in respect of the 5.9% minority interest in TNK-BP.

Movements in estimated net proved reserves on an SEC basis

2004

Crude oil[a]

million barrels

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiary									
At 1 January 2004									
Developed	697	236	1,902	385	82	190	–	73	3,565
Undeveloped	245	127	1,499	354	81	632	–	711	3,649
	942	363	3,401	739	163	822	–	784	7,214
Changes attributable to									
Revisions of previous estimates	(133)	1	(44)	(92)	2	19	–	(192)	(439)
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	24	–	74	5	8	48	–	213	372
Improved recovery	57	4	55	31	–	6	–	3	156
Production[b]	(121)	(28)	(217)	(63)	(17)	(48)	–	(21)	(515)
Sales of reserves-in-place	–	–	(17)	(10)	(6)	–	–	–	(33)
	(173)	(23)	(149)	(129)	(13)	25	–	3	(459)
At 31 December 2004[c]									
Developed	559	231	2,041	311	65	204	–	62	3,473
Undeveloped	210	109	1,211	299	85	643	–	725	3,282
	769	340	3,252	610	150	847	–	787	6,755
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	–	–	–	206	1	–	1,384	705	2,296
Undeveloped	–	–	–	134	–	–	410	27	571
	–	–	–	340	1	–	1,794	732	2,867
Changes attributable to									
Revisions of previous estimates	–	–	–	(5)	–	–	382	15	392
Purchases of reserves-in-place	–	–	–	–	–	–	252	–	252
Extensions, discoveries and other additions	–	–	–	2	–	–	–	–	2
Improved recovery	–	–	–	17	–	–	37	–	54
Production	–	–	–	(25)	–	–	(304)	(55)	(384)
Sales of reserves-in-place	–	–	–	–	–	–	(4)	–	(4)
	–	–	–	(11)	–	–	363	(40)	312
At 31 December 2004[d]									
Developed	–	–	–	204	1	–	1,863	592	2,660
Undeveloped	–	–	–	125	–	–	294	100	519
	–	–	–	329	1	–	2,157	692	3,179

[a]Crude oil includes natural gas liquids (NGLs) and condensate. Net proved reserves of crude oil exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b]Excludes NGLs from processing plants in which an interest is held of 67 thousand barrels a day.
[c]Includes 40 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 127 million barrels of crude oil in respect of the 5.9% minority interest in TNK-BP.

Movements in estimated net proved reserves on an SEC basis *continued*

2004

Natural gas[a]

billion cubic feet

	UK	Rest of Europe	USA	Rest of Americas	Asia Pacific	Africa	Russia	Other	Total
Subsidiary									
At 1 January 2004									
Developed	2,996	262	11,482	4,212	1,976	640	–	255	21,823
Undeveloped	1,095	1,255	3,337	11,531	3,026	2,188	–	900	23,332
	4,091	1,517	14,819	15,743	5,002	2,828	–	1,155	45,155
Changes attributable to									
Revisions of previous estimates	(210)	28	(438)	(1,081)	106	16	–	558	(1,021)
Purchases of reserves-in-place	–	–	3	2	–	–	–	–	5
Extensions, discoveries and other additions	127	–	140	991	2,478	233	–	3	3,972
Improved recovery	134	4	870	76	–	29	–	38	1,151
Production[b]	(461)	(47)	(1,111)	(875)	(296)	(102)	–	(76)	(2,968)
Sales of reserves-in-place	–	–	(202)	(92)	(247)	(103)	–	–	(644)
	(410)	(15)	(738)	(979)	2,041	73	–	523	495
At 31 December 2004[c]									
Developed	2,498	248	10,811	4,101	1,624	1,015	–	282	20,579
Undeveloped	1,183	1,254	3,270	10,663	5,419	1,886	–	1,396	25,071
	3,681	1,502	14,081	14,764	7,043	2,901	–	1,678	45,650
Equity-accounted entities (BP share)									
At 1 January 2004									
Developed	–	–	–	1,591	136	–	46	58	1,831
Undeveloped	–	–	–	916	80	–	14	28	1,038
	–	–	–	2,507	216	–	60	86	2,869
Changes attributable to									
Revisions of previous estimates	–	–	–	(12)	(17)	–	341	–	312
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Extensions, discoveries and other additions	–	–	–	–	–	–	–	–	–
Improved recovery	–	–	–	23	–	–	–	–	23
Production[b]	–	–	–	(144)	(23)	–	(177)	(3)	(347)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	(133)	(40)	–	164	(3)	(12)
At 31 December 2004[d]									
Developed	–	–	–	1,397	107	–	214	60	1,778
Undeveloped	–	–	–	977	69	–	10	23	1,079
	–	–	–	2,374	176	–	224	83	2,857

[a]Net proved reserves of natural gas exclude production royalties due to others, whether royalty is payable in cash or in kind.
[b]Includes 190 billion cubic feet of natural gas consumed in operations (165 bcf in subsidiaries, 25 bcf in equity-accounted entities).
[c]Includes 4,064 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[d]Includes 13 billion cubic feet of natural gas in respect of the 5.9% minority interest in TNK-BP.

Group production interests – oil (includes NGLs and condensate)

		Field	Interest %	BP net share of production thousand barrels a day[a] 2004	2003
UK	Offshore	ETAP[b]	Various	55	56
		Foinaven[c]	Various	48	55
		Schiehallion/Loyal[c]	Various	39	42
		Magnus[c]	85.0	34	39
		Harding[c]	70.0	27	34
		Andrew[c]	62.8	12	17
		Other	Various	89	105
	Onshore	Wytch Farm[c]	67.8	26	29
				330	377
Rest of Europe	Netherlands	Various	Various	1	22
	Norway	Draugen	18.4	27	25
		Valhall[c]	28.1	25	21
		Ula[c]	80.0	16	16
		Other	Various	8	–
				77	84
USA	Alaska	Prudhoe Bay[c]	26.4	97	105
		Kuparuk	39.2	68	73
		Northstar[c]	98.6	49	46
		Milne Point[c]	100.0	44	44
		Other	Various	37	43
	Lower 48 onshore	Various	Various	142	160
	Gulf of Mexico	Horn Mountain[c]	66.6	41	42
		Mars	28.5	35	43
		Ursa	22.7	29	17
		Na Kika[c]	50.0	27	–
		King[c]	100.0	26	31
		Other	Various	71	122
				666	726
Rest of World	Angola	Girassol	16.7	31	33
		Xikomba	26.7	18	2
		Kizomba A	26.7	16	–
		Other	Various	6	–
	Australia	Various	15.8	36	40
	Azerbaijan	ACG (Chirag)[c]	34.1	39	38
	Canada	Various	Various	11	13
	Colombia	Various	Various	48	53
	Egypt	Various	Various	57	73
	Trinidad	Various	100.0	59	74
	Venezuela	Various	Various	55	53
	Other	Various	Various	31	49
				407	428
Total group				1,480	1,615
Equity-accounted entities (BP share)	Abu Dhabi	Various	Various	142	138
	Argentina – Pan American Energy	Various	Various	64	60
	Russia – TNK-BP	Various	Various	831	296
	Other	Various	Various	14	12
Total equity-accounted entities				1,051	506
Total group and BP share of equity-accounted entities[d]				2,531	2,121

[a]Net of royalty, whether payable in cash or in kind.
[b]Out of nine fields, BP operates six and Shell three.
[c]BP operator.
[d]Includes natural gas liquids (NGLs) from processing plants in which an interest is held of 67 thousand barrels a day (70 thousand barrels a day in 2003).

Group production interests – natural gas

		Field	Interest %	BP net share of production million cubic feet a day[a] 2004	2003
UK	Offshore	Bruce[b]	37.0	163	222
		Braes	Various	147[c]	174
		Shearwater	27.5	76	70
		Marnock[b]	62.0	70	98
		West Sole[b]	*100.0*	67	73
		Britannia	9.0	54	55
		Armada	18.2	50	58
		Other	Various	547	696
				1,174	1,446
Rest of Europe	Netherlands	P/18-2[b]	48.7	34	30
		Other	Various	46	37
	Norway	Various	Various	45	52
				125	119
USA	Lower 48 onshore	San Juan[b]	Various	772	802
		Arkoma	Various	183	201
		Hugoton[b]	Various	158	182
		Jonah[b]	65.0	114	119
		Wamsutter[b]	70.5	105	111
		Tuscaloosa	Various	96	136
		Other	Various	514	558
	Gulf of Mexico	Na Kika[b]	50.0	133	–
		Marlin[b]	78.2	43	93
		King's Peak[b]	55.0	39	91
		Other	Various	514	752
	Alaska	Various	Various	78	83
				2,749	3,128
Rest of World	Australia	Various	15.8	308	285
	Canada	Various	Various	349	422
	China	Yacheng[b]	34.3	99	74
	Egypt	Ha'py[b]	50.0	80	83
		Other	Various	115	170
	Indonesia	Sanga-Sanga (direct)[b]	26.3	137	165
		Pagerungan[d]	100.0	68	121
		Other[b]	46.0	76	97
	Sharjah	Sajaa[b]	40.0	103	101
		Other	40.0	14	19
	Trinidad	Kapok[b]	100.0	553	79
		Mahogany[b]	100.0	453	503
		Amherstia[b]	100.0	408	624
		Immortelle[b]	100.0	172	235
		Parang[b]	100.0	137	152
		Cassia[b]	100.0	85	30
		Flamboyant[b]	100.0	67	68
		Other[b]	100.0	44	3
	Other	Various	Various	308	168
				3,576	3,399
Total group				7,624	8,092
Equity-accounted entities (BP share)	Argentina – Pan American Energy	Various	Various	317	281
	Russia – TNK-BP	Various	Various	458	129
	Other	Various	Various	104	111
Total equity-accounted entities				879	521
Total group and BP share of equity-accounted entities				8,503	8,613

[a] Net of royalty, whether payable in cash or in kind.
[b] BP operator.
[c] Includes 7 million cubic feet a day of natural gas received as in-kind tariff payments.
[d] Interest divested during 2004.

Five-year summaries*

Summarized group income statement

$ million

	2000	2001	2002	2003	2004
Turnover	161,826	175,389	180,186	236,045	294,849
Less: joint ventures	13,764	1,171	1,465	3,474	9,790
Group turnover	148,062	174,218	178,721	232,571	285,059
Replacement cost of sales	120,797	147,001	155,742	201,347	248,714
Production taxes	2,061	1,689	1,274	1,723	2,149
Gross profit	25,204	25,528	21,705	29,501	34,196
Distribution and administration expenses[a]	9,331	10,918	12,632	14,072	14,988
Exploration expense	599	480	644	542	637
	15,274	14,130	8,429	14,887	18,571
Other income	805	694	641	786	675
Group replacement cost operating profit	16,079	14,824	9,070	15,673	19,246
Share of profits of joint ventures	808	443	346	923	2,933
Share of profits of associated undertakings	792	760	616	511	605
Total replacement cost operating profit	17,679	16,027	10,032	17,107	22,784
Exceptional items	220	535	1,168	831	815
Replacement cost profit before interest and tax	17,899	16,562	11,200	17,938	23,599
Stock holding gains (losses)	728	(1,900)	1,129	16	1,643
Historical cost profit before interest and tax	18,627	14,662	12,329	17,954	25,242
Interest expense	1,581	1,432	1,067	644	642
Other finance expense	189	238	73	547	357
Profit before taxation	16,857	12,992	11,189	16,763	24,243
Taxation	6,648	6,375	4,317	6,111	8,282
Profit after taxation	10,209	6,617	6,872	10,652	15,961
Minority shareholders' interest	89	61	77	170	230
Profit for the year	10,120	6,556	6,795	10,482	15,731
Distribution to shareholders	4,625	4,935	5,375	5,753	6,371
Retained profit for the year	5,495	1,621	1,420	4,729	9,360
Earnings per ordinary share – cents					
Basic	46.77	29.21	30.33	47.27	72.08
Diluted	46.46	29.04	30.19	46.83	70.79
Dividends per ordinary share – cents	20.50	22.00	24.00	26.00	29.45
Replacement cost results[b]					
Historical cost profit for the year	10,120	6,556	6,795	10,482	15,731
Stock holding (gains) losses	(728)	1,900	(1,104)	(16)	(1,643)
Replacement cost profit for the year	9,392	8,456	5,691	10,466	14,088
Earnings per ordinary share – cents					
On replacement cost profit for the year	43.40	37.68	25.40	47.20	64.55
[a]Research and development expenditure amounted to:	434	385	373	349	439

[b]Replacement cost profit excludes stock holding gains and losses. The effect of this is to set against income for the period the average cost of supplies incurred in the same period rather than applying costs obtained by using the first-in first-out method. Profit on the replacement cost basis therefore reflects more immediately changes in purchase costs and provides an indication of the underlying trend in trading performance in a continuing business. This basis is used to assist in the interpretation of operating profit.

US dollar/sterling exchange rates

Average exchange rate for the year	1.51	1.44	1.50	1.63	1.83
Year-end exchange rate	1.49	1.45	1.60	1.78	1.92

US dollar/euro exchange rates

Average exchange rate for the year	0.92	0.89	0.94	1.13	1.24
Year-end exchange rate	0.93	0.88	1.05	1.25	1.36

*The financial information for 2002 and 2003 has been restated to reflect the adoption by the group of Financial Reporting Standard No. 17 'Retirement Benefits' (FRS 17) with effect from 1 January 2004. The financial information for 2000 and 2001 has not been restated for FRS 17.

Summarized group income statement (by quarter)

Replacement cost results

	Q1	Q2	Q3	Q4	**2000**	Q1	Q2	Q3	Q4	**2001**
Replacement cost profit before interest and tax										
By business[a]										
Exploration and Production	3,211	3,147	3,517	4,098	**13,973**	4,584	3,729	2,613	1,546	**12,472**
Refining and Marketing	603	1,177	1,112	692	**3,584**	1,005	1,405	1,237	397	**4,044**
Petrochemicals	49	320	233	(54)	**548**	75	(71)	24	(197)	**(169)**
Gas, Power and Renewables	165	134	154	199	**652**	139	178	142	113	**572**
Other businesses and corporate[b]	(224)	(303)	(210)	(121)	**(858)**	(113)	(125)	(102)	(17)	**(357)**
Replacement cost profit before interest and tax	3,804	4,475	4,606	4,814	**17,899**	5,690	5,116	3,914	1,842	**16,562**
Interest expense	260	358	412	551	**1,581**	393	391	322	326	**1,432**
Other finance expense	36	45	48	60	**189**	53	50	47	88	**238**
Replacement cost profit before taxation	3,508	4,072	4,346	4,203	**16,129**	5,244	4,675	3,545	1,428	**14,892**
Taxation	1,253	1,712	1,873	1,810	**6,648**	2,168	1,956	1,540	711	**6,375**
Replacement cost profit after taxation	2,255	2,360	2,473	2,393	**9,481**	3,076	2,719	2,005	717	**8,517**
Minority shareholders' interest	68	(5)	12	14	**89**	8	18	12	23	**61**
Replacement cost profit for the period	2,187	2,365	2,461	2,379	**9,392**	3,068	2,701	1,993	694	**8,456**
Earnings on replacement cost profit										
per ordinary share – cents	11.26	10.70	10.89	10.55	**43.40**	13.65	12.03	8.89	3.11	**37.68**
per ADS – dollars	0.68	0.64	0.65	0.63	**2.60**	0.82	0.72	0.53	0.19	**2.26**
Historical cost results										
Replacement cost profit for the period	2,187	2,365	2,461	2,379	**9,392**	3,068	2,701	1,993	694	**8,456**
Stock holding gains (losses)	532	213	544	(561)	**728**	(238)	40	(405)	(1,297)	**(1,900)**
Historical cost profit (loss) for the period	2,719	2,578	3,005	1,818	**10,120**	2,830	2,741	1,588	(603)	**6,556**
Earnings on historical cost profit										
per ordinary share – cents										
Basic	14.00	11.56	13.34	7.87	**46.77**	12.59	12.21	7.08	(2.67)	**29.21**
Diluted	13.90	11.47	13.26	7.83	**46.46**	12.51	12.14	7.03	(2.64)	**29.04**
per ADS – dollars										
Basic	0.84	0.69	0.80	0.47	**2.80**	0.76	0.73	0.43	(0.16)	**1.76**
Diluted	0.83	0.69	0.80	0.47	**2.79**	0.75	0.73	0.42	(0.16)	**1.74**

[a] Replacement cost profit is after exceptional items and excluding stock holding gains and losses.
[b] Other businesses and corporate comprises Finance, the group's coal asset (divested in October 2003) and aluminium asset, its investments in PetroChina and Sinopec (both divested in early 2004), interest income and costs relating to corporate activities worldwide.

$ million

Q1	Q2	Q3	Q4	2002	Q1	Q2	Q3	Q4	2003	Q1	Q2	Q3	Q4	2004
1,887	2,839	1,490	2,061	**8,277**	4,718	3,434	3,666	2,848	**14,666**	4,242	4,302	4,883	5,093	**18,520**
35	647	511	340	**1,533**	628	888	482	320	**2,318**	720	1,344	1,081	1,577	**4,722**
(8)	94	120	(41)	**165**	137	306	84	41	**568**	(25)	208	188	(1,271)	**(900)**
123	125	1,664	57	**1,969**	216	141	127	86	**570**	198	216	130	399	**943**
(141)	(131)	(287)	(185)	**(744)**	(166)	(153)	(330)	465	**(184)**	1,129	(164)	(424)	(227)	**314**
1,896	3,574	3,498	2,232	**11,200**	5,533	4,616	4,029	3,760	**17,938**	6,264	5,906	5,858	5,571	**23,599**
290	272	257	248	**1,067**	176	149	159	160	**644**	152	145	156	189	**642**
8	7	8	50	**73**	129	127	139	152	**547**	76	76	79	126	**357**
1,598	3,295	3,233	1,934	**10,060**	5,228	4,340	3,731	3,448	**16,747**	6,036	5,685	5,623	5,256	**22,600**
747	1,746	707	1,117	**4,317**	1,782	1,744	1,428	1,157	**6,111**	1,822	2,199	2,109	2,152	**8,282**
851	1,549	2,526	817	**5,743**	3,446	2,596	2,303	2,291	**10,636**	4,214	3,486	3,514	3,104	**14,318**
9	34	3	6	**52**	26	60	43	41	**170**	44	52	58	76	**230**
842	1,515	2,523	811	**5,691**	3,420	2,536	2,260	2,250	**10,466**	4,170	3,434	3,456	3,028	**14,088**
3.76	6.75	11.26	3.63	**25.40**	15.32	11.45	10.25	10.18	**47.20**	18.88	15.68	15.96	14.03	**64.55**
0.23	0.41	0.68	0.22	**1.52**	0.92	0.69	0.62	0.61	**2.83**	1.13	0.94	0.96	0.84	**3.87**

$ million

842	1,515	2,523	811	**5,691**	3,420	2,536	2,260	2,250	**10,466**	4,170	3,434	3,456	3,028	**14,088**
442	531	305	(174)	**1,104**	799	(951)	84	84	**16**	648	462	1,027	(494)	**1,643**
1,284	2,046	2,828	637	**6,795**	4,219	1,585	2,344	2,334	**10,482**	4,818	3,896	4,483	2,534	**15,731**
5.73	9.12	12.62	2.86	**30.33**	18.90	7.19	10.62	10.56	**47.27**	21.81	17.80	20.67	11.80	**72.08**
5.70	9.07	12.56	2.86	**30.19**	18.84	7.16	10.51	10.32	**46.83**	21.34	17.43	20.41	11.61	**70.79**
0.34	0.55	0.76	0.17	**1.82**	1.13	0.43	0.64	0.63	**2.84**	1.31	1.07	1.24	0.70	**4.32**
0.34	0.54	0.75	0.17	**1.81**	1.13	0.43	0.63	0.62	**2.81**	1.28	1.05	1.22	0.70	**4.25**

Replacement cost profit before interest and tax analysed by business and geographical area

By business	Q1	Q2	Q3	Q4	2000	Q1	Q2	Q3	Q4	2001
Exploration and Production										
UK	1,098	875	990	1,067	**4,030**	1,150	951	726	568	**3,395**
Rest of Europe	188	185	221	232	**826**	234	191	186	143	**756**
USA	1,206	1,355	1,220	1,570	**5,351**	2,047	1,186	824	404	**4,461**
Rest of World	719	732	1,086	1,229	**3,766**	1,153	1,401	875	431	**3,860**
	3,211	3,147	3,517	4,098	**13,973**	4,584	3,729	2,613	1,546	**12,472**
Refining and Marketing										
UK[a]	34	148	71	(76)	**177**	(102)	(119)	(62)	(410)	**(693)**
Rest of Europe	55	135	233	313	**736**	129	175	220	269	**793**
USA	405	798	740	334	**2,277**	868	1,211	943	(168)	**2,854**
Rest of World	109	96	68	121	**394**	110	138	136	706	**1,090**
	603	1,177	1,112	692	**3,584**	1,005	1,405	1,237	397	**4,044**
Petrochemicals										
UK	(29)	(33)	(43)	36	**(69)**	(49)	(33)	(124)	(99)	**(305)**
Rest of Europe	76	118	76	14	**284**	79	19	81	(1)	**178**
USA	158	177	145	49	**529**	(6)	(94)	42	(28)	**(86)**
Rest of World	(156)	58	55	(153)	**(196)**	51	37	25	(69)	**44**
	49	320	233	(54)	**548**	75	(71)	24	(197)	**(169)**
Gas, Power and Renewables										
UK	–	7	18	4	**29**	14	41	39	(25)	**69**
Rest of Europe	54	11	28	57	**150**	63	35	27	64	**189**
USA	34	64	32	45	**175**	60	99	94	43	**296**
Rest of World	77	52	76	93	**298**	2	3	(18)	31	**18**
	165	134	154	199	**652**	139	178	142	113	**572**
Other businesses and corporate										
UK	(111)	(29)	(53)	(189)	**(382)**	(76)	(51)	(91)	100	**(118)**
Rest of Europe	10	17	21	(50)	**(2)**	(18)	8	(12)	(47)	**(69)**
USA	(129)	(297)	(165)	(114)	**(705)**	(56)	(64)	(101)	(119)	**(342)**
Rest of World	6	6	(13)	232	**231**	39	(18)	102	49	**172**
	(224)	(303)	(210)	(121)	**(858)**	(113)	(125)	(102)	(17)	**(357)**
By geographical area										
UK[a]	992	968	983	842	**3,785**	937	789	488	134	**2,348**
Rest of Europe	383	466	579	566	**1,994**	487	428	504	428	**1,847**
USA	1,674	2,097	1,972	1,884	**7,627**	2,911	2,338	1,602	132	**7,183**
Rest of World	755	944	1,272	1,522	**4,493**	1,355	1,561	1,120	1,148	**5,184**
Total replacement cost profit before interest and tax	3,804	4,475	4,806	4,814	**17,899**	5,690	5,116	3,914	1,842	**16,562**

[a] UK area includes the UK-based international activities of Refining and Marketing.

Exceptional items

	Q1	Q2	Q3	Q4	2000	Q1	Q2	Q3	Q4	2001
Exploration and Production	38	168	9	(96)	**119**	(42)	319	3	(85)	**195**
Refining and Marketing	19	5	161	(87)	**98**	265	(59)	247	18	**471**
Petrochemicals	(210)	–	(30)	28	**(212)**	(6)	(80)	(81)	(130)	**(297)**
Gas, Power and Renewables	–	–	(1)	3	**2**	(1)	–	–	1	**–**
Other businesses and corporate	(4)	(12)	(1)	230	**213**	2	(9)	15	158	**166**
Profit (loss) on sale of fixed assets and businesses or termination of operations	(157)	161	138	78	**220**	218	171	184	(38)	**535**
Taxation	101	(104)	(89)	(50)	**(142)**	(151)	(118)	(127)	26	**(370)**
Exceptional items after taxation and minority shareholders' interest	(56)	57	49	28	**78**	67	53	57	(12)	**165**

$ million

Q1	Q2	Q3	Q4	2002	Q1	Q2	Q3	Q4	2003	Q1	Q2	Q3	Q4	2004
682	587	107	918	**2,294**	1,078	993	672	654	**3,397**	823	835	745	981	**3,384**
159	176	212	177	**724**	195	143	95	154	**587**	163	206	246	222	**837**
317	1,258	666	117	**2,358**	1,658	1,374	1,352	716	**5,100**	1,494	1,503	1,566	1,531	**6,094**
729	818	505	849	**2,901**	1,787	924	1,547	1,324	**5,582**	1,762	1,758	2,326	2,359	**8,205**
1,887	2,839	1,490	2,061	**8,277**	4,718	3,434	3,666	2,848	**14,666**	4,242	4,302	4,883	5,093	**18,520**
(183)	(98)	(185)	(224)	**(690)**	(43)	(117)	(160)	(152)	**(472)**	(189)	(195)	(152)	101	**(435)**
193	301	374	95	**963**	361	499	355	158	**1,373**	289	444	533	593	**1,859**
(105)	294	227	354	**770**	145	337	92	174	**748**	409	872	536	661	**2,478**
130	150	95	115	**490**	165	169	195	140	**669**	211	223	164	222	**820**
35	647	511	340	**1,533**	628	888	482	320	**2,318**	720	1,344	1,081	1,577	**4,722**
(63)	(67)	(47)	(88)	**(265)**	(90)	(38)	(132)	(65)	**(325)**	(156)	(62)	(107)	(716)	**(1,041)**
48	16	195	65	**324**	117	232	93	34	**476**	154	183	130	(282)	**185**
(41)	48	45	23	**75**	54	82	63	6	**205**	(109)	3	30	(215)	**(291)**
48	97	(73)	(41)	**31**	56	30	60	66	**212**	86	84	135	(58)	**247**
(8)	94	120	(41)	**165**	137	306	84	41	**568**	(25)	208	188	(1,271)	**(900)**
5	4	(30)	(26)	**(47)**	4	17	15	40	**76**	12	(2)	(46)	133	**97**
47	34	1,569	35	**1,685**	(9)	(5)	(12)	(11)	**(37)**	(11)	(3)	(9)	(4)	**(27)**
(15)	23	48	(43)	**13**	57	126	78	5	**266**	79	114	139	90	**422**
86	64	77	91	**318**	164	3	46	52	**265**	118	107	46	180	**451**
123	125	1,664	57	**1,969**	216	141	127	86	**570**	198	216	130	399	**943**
(62)	(90)	(138)	29	**(261)**	(93)	(149)	(108)	324	**(26)**	(163)	(50)	(147)	282	**(78)**
1	6	(7)	33	**33**	(8)	(2)	3	(42)	**(49)**	(6)	(1)	21	(177)	**(163)**
(71)	(22)	(122)	(237)	**(452)**	(81)	(43)	(237)	(23)	**(384)**	(30)	(109)	(268)	(251)	**(658)**
(9)	(25)	(20)	(10)	**(64)**	16	41	12	206	**275**	1,328	(4)	(30)	(81)	**1,213**
(141)	(131)	(287)	(185)	**(744)**	(166)	(153)	(330)	465	**(184)**	1,129	(164)	(424)	(227)	**314**
379	336	(293)	609	**1,031**	856	706	287	801	**2,650**	327	526	293	781	**1,927**
448	533	2,343	405	**3,729**	656	867	534	293	**2,350**	589	829	921	352	**2,691**
85	1,601	864	214	**2,764**	1,833	1,876	1,348	878	**5,935**	1,843	2,383	2,003	1,816	**8,045**
984	1,104	584	1,004	**3,676**	2,188	1,167	1,860	1,788	**7,003**	3,505	2,168	2,641	2,622	**10,936**
1,896	3,574	3,498	2,232	**11,200**	5,533	4,616	4,029	3,760	**17,938**	6,264	5,906	5,858	5,571	**23,599**

$ million

Q1	Q2	Q3	Q4	2002	Q1	Q2	Q3	Q4	2003	Q1	Q2	Q3	Q4	2004
5	427	(25)	(1,133)	**(726)**	433	333	196	(49)	**913**	211	(114)	23	32	**152**
(45)	31	262	365	**613**	(52)	(49)	(21)	(91)	**(213)**	(140)	(18)	(17)	58	**(117)**
(60)	(85)	11	(122)	**(256)**	7	2	13	16	**38**	(154)	6	(38)	(377)	**(563)**
–	(1)	1,585	(33)	**1,551**	–	6	(2)	(10)	**(6)**	–	–	16	40	**56**
(9)	4	(39)	30	**(14)**	6	(12)	(14)	119	**99**	1,313	(1)	1	(26)	**1,287**
(109)	376	1,794	(893)	**1,168**	394	280	172	(15)	**831**	1,230	(127)	(15)	(273)	**815**
39	(160)	(25)	21	**(125)**	(54)	(149)	(4)	84	**(123)**	70	28	33	130	**261**
(70)	216	1,769	(872)	**1,043**	340	131	168	69	**708**	1,300	(99)	18	(143)	**1,076**

Turnover

$ million

By business	2000	2001	2002	2003	2004
Exploration and Production	30,272	27,540	25,083	30,753	34,914
Refining and Marketing	107,883	120,233	125,836	149,477	179,587
Petrochemicals	11,247	11,515	13,064	16,075	21,209
Gas, Power and Renewables	21,426	39,671	37,580	65,639	83,320
Other businesses and corporate	59	549	510	515	546
	170,887	199,508	202,073	262,459	319,576
Less: Sales between businesses	22,825	25,290	23,352	29,888	34,517
Group turnover	148,062	174,218	178,721	232,571	285,059
Add: Share of joint venture sales	13,764	1,171	1,465	3,474	9,790
Turnover	161,826	175,389	180,186	236,045	294,849
By geographical area					
UK[a]	45,400	47,618	48,748	54,971	81,155
Rest of Europe	20,553	36,701	46,518	50,582	54,422
USA	71,084	84,696	80,381	108,910	130,652
Rest of World	31,014	33,911	34,401	52,498	68,052
	168,051	202,926	210,048	266,961	334,281
Less: Sales between areas	19,989	28,708	31,327	34,390	49,222
Group turnover	148,062	174,218	178,721	232,571	285,059

[a] UK area includes the UK-based international activities of Refining and Marketing.

Taxation

$ million

	2000	2001	2002	2003	2004
Production taxes provided for					
UK petroleum revenue tax	707	600	309	300	335
Overseas production taxes	1,354	1,089	965	1,423	1,814
	2,061	1,689	1,274	1,723	2,149
Production taxes paid					
UK petroleum revenue tax	676	410	231	424	498
Overseas production taxes	1,466	1,114	930	1,386	1,709
	2,142	1,524	1,161	1,810	2,207
Tax on profit on ordinary activities					
Current tax					
UK	1,195	988	1,003	1,142	1,839
Overseas	3,704	3,846	1,883	3,525	5,070
Group	4,899	4,834	2,886	4,667	6,909
Joint ventures	57	94	75	158	880
Associated undertakings	128	203	187	94	119
	5,084	5,131	3,148	4,919	7,908
Deferred tax					
UK	12	(48)	390	289	(140)
Overseas	1,552	1,292	779	931	340
Group	1,564	1,244	1,169	1,220	200
Joint ventures	–	–	–	(14)	170
Associated undertakings	–	–	–	(14)	4
	1,564	1,244	1,169	1,192	374
Tax on profit on ordinary activities	6,648	6,375	4,317	6,111	8,282
Effective tax rates on					
Replacement cost basis	41%	43%	43%	36%	37%
Historical cost basis	39%	49%	39%	36%	34%
Profit taxes paid					
UK	869	1,058	979	1,185	1,447
Overseas	5,329	3,602	2,115	3,619	4,931
	6,198	4,660	3,094	4,804	6,378

Depreciation and amounts provided

$ million

By business	2000	2001	2002	2003	2004
Exploration and Production[a]					
UK	1,498	1,397	1,921	1,890	1,738
Rest of Europe	98	115	154	168	184
USA	2,554	3,147	3,161	3,482	3,361
Rest of World	770	1,121	1,550	1,388	1,594
	4,920	5,780	6,786	6,928	6,877
Refining and Marketing[a]					
UK[b]	323	603	653	762	863
Rest of Europe	145	278	547	644	789
USA	1,080	1,228	1,222	1,301	1,495
Rest of World	204	193	236	251	276
	1,752	2,302	2,658	2,958	3,423
Petrochemicals					
UK	99	122	184	200	617
Rest of Europe	109	117	162	194	656
USA	299	271	286	285	486
Rest of World	197	78	117	72	192
	704	588	749	751	1,951
Gas, Power and Renewables					
UK	3	6	34	34	37
Rest of Europe	3	3	4	22	24
USA	41	61	63	72	85
Rest of World	20	22	29	35	69
	67	92	130	163	215
Other businesses and corporate					
UK	12	29	29	77	59
Rest of Europe	1	–	–	–	–
USA	70	67	48	47	57
Rest of World	–	–	1	16	1
	83	96	78	140	117
By geographical area					
UK[b]	1,935	2,157	2,821	2,963	3,314
Rest of Europe	356	513	867	1,028	1,653
USA	4,044	4,774	4,780	5,187	5,484
Rest of World	1,191	1,414	1,933	1,762	2,132
Total[c]	7,526	8,858	10,401	10,940	12,583
Excludes the following amounts of depreciation of the BP/Mobil European joint venture	172	–	–	–	–
[a]Acquisition amortization					
Exploration and Production	1,214	1,815	1,780	1,566	1,239
Refining and Marketing	477	770	794	826	881

[b]UK area includes the UK-based international activities of Refining and Marketing.
[c]Includes amounts provided against fixed asset investments.

Group balance sheet

					$ million
	2000	2001	2002	2003	2004
Tangible assets[a]					
Exploration and Production	46,447	47,983	51,915	53,543	57,592
Refining and Marketing	17,619	16,903	22,433	24,255	24,640
Petrochemicals	8,360	9,242	10,080	10,591	10,660
Gas, Power and Renewables	1,744	1,931	1,889	2,158	2,331
Other businesses and corporate	1,003	1,351	1,365	1,364	1,525
	75,173	77,410	87,682	91,911	96,748
Intangible assets[a]	17,897	16,489	15,566	13,642	12,076
Investments[a]					
Net investment in joint ventures[b]	2,884	3,861	4,031	11,009	12,451
Associated undertakings	5,375	5,433	4,626	4,870	5,488
Other	3,054	2,403	1,995	1,579	467
	11,313	11,697	10,652	17,458	18,406
Total fixed assets	104,383	105,596	113,900	123,011	127,230
Current assets					
Business held for resale	636	–	–	–	–
Stocks	9,234	7,631	10,181	11,617	15,698
Debtors	28,418	26,669	29,251	33,902	46,696
Investments	661	450	215	185	328
Cash at bank and in hand	1,170	1,358	1,520	1,947	1,156
	40,119	36,108	41,167	47,651	63,878
Creditors – amounts falling due within one year					
Finance debt	6,418	9,090	10,086	9,456	10,184
Other creditors	32,110	28,524	36,215	41,128	54,341
Net current assets (liabilities)	1,591	(1,506)	(5,134)	(2,933)	(647)
Total assets less current liabilities	105,974	104,090	108,766	120,078	126,583
Creditors – amounts falling due after one year					
Finance debt	14,772	12,327	11,922	12,869	12,907
Other creditors	3,821	3,054	3,412	6,030	4,505
Provisions for liabilities and charges					
Deferred taxation	10,595	11,702	13,514	14,371	15,050
Other provisions	10,776	11,266	7,836	8,599	9,608
Net assets excluding pension and other post-retirement benefit balances	66,010	65,741	72,082	78,209	84,513
Defined benefit pension plan surplus	–	–	388	1,146	1,475
Defined benefit pension plan deficits	–	–	(5,250)	(5,005)	(5,863)
Other post-retirement benefit plan deficit	–	–	(2,748)	(2,630)	(2,126)
Net assets	66,010	65,741	64,472	71,720	77,999
Minority shareholders' interest – equity	568	598	638	1,125	1,343
BP shareholders' interest	65,442	65,143	63,834	70,595	76,656
Represented by					
Called up share capital	5,653	5,629	5,616	5,552	5,403
Share premium account	3,385	3,590	3,794	3,957	5,636
Capital redemption reserve	385	424	449	523	730
Merger reserve	26,869	26,983	27,033	27,077	27,162
Other reserves	456	223	173	129	44
Shares held by ESOP trusts	(360)	(266)	(159)	(96)	(82)
Profit and loss account	29,054	28,560	26,928	33,453	37,763
Capital and reserves	65,442	65,143	63,834	70,595	76,656
[a]Fixed asset revaluation adjustment and goodwill consequent upon the ARCO and Burmah Castrol acquisitions					
Tangible assets	9,085	6,787	5,804	3,983	3,520
Intangible assets	12,927	11,663	10,439	9,125	7,638
Fixed asset investments	584	432	429	254	232
	22,596	18,882	16,672	13,362	11,390
[b]Net investment in joint ventures					
Gross assets	3,641	4,661	4,829	16,485	19,309
Gross liabilities	(757)	(800)	(798)	(5,111)	(6,316)
Minority shareholders' interest	–	–	–	(365)	(542)
	2,884	3,861	4,031	11,009	12,451

Capital employed

					$ million
By business	2000	2001	2002	2003	2004
Exploration and Production[a]					
UK	10,414	10,045	9,160	8,974	8,952
Rest of Europe	814	1,049	1,452	1,476	1,558
USA	27,354	28,703	28,169	26,853	27,354
Rest of World	18,089	20,035	22,679	26,315	30,854
	56,671	59,832	61,460	63,618	68,718
Refining and Marketing[a]					
UK[b]	6,731	6,113	6,125	6,510	6,616
Rest of Europe	3,244	2,621	9,488	9,832	11,618
USA	14,026	12,984	13,952	14,125	15,296
Rest of World	4,306	3,601	3,919	4,644	5,047
	28,307	25,319	33,484	35,111	38,577
Petrochemicals					
UK	2,989	2,976	2,512	2,907	3,048
Rest of Europe	1,990	2,421	3,340	3,850	4,900
USA	4,211	4,352	4,480	4,478	4,337
Rest of World	1,818	2,247	2,204	2,249	2,470
	11,008	11,996	12,536	13,484	14,755
Gas, Power and Renewables					
UK	450	469	443	798	902
Rest of Europe	763	938	426	425	463
USA	1,149	1,115	1,056	1,672	1,700
Rest of World	1,176	917	1,054	1,397	1,836
	3,538	3,439	2,979	4,292	4,901
Other businesses and corporate					
UK	(654)	(176)	65	(401)	1,641
Rest of Europe	276	317	(3,531)	(4,553)	(5,247)
USA	(1,317)	(2,183)	(4,962)	(2,806)	(5,180)
Rest of World	3,647	3,429	(1,340)	1,368	227
	1,952	1,387	(9,768)	(6,392)	(8,559)
Total operating capital employed	101,476	101,973	100,691	110,113	118,392
By geographical area					
UK[b]	19,930	19,427	18,305	18,788	21,342
Rest of Europe	7,087	7,346	11,175	11,030	13,109
USA	45,423	44,971	42,695	44,322	43,507
Rest of World	29,036	30,229	28,516	35,973	40,434
Total operating capital employed	101,476	101,973	100,691	110,113	118,392
Liabilities for current and deferred taxation	(14,276)	(14,815)	(14,211)	(16,068)	(17,302)
Capital employed	87,200	87,158	86,480	94,045	101,090
Financed by					
Finance debt	21,190	21,417	22,008	22,325	23,091
Minority shareholders' interest	568	598	638	1,125	1,343
BP shareholders' interest	65,442	65,143	63,834	70,595	76,656
Capital employed	87,200	87,158	86,480	94,045	101,090
[a]Capital employed acquisition adjustment consequent upon the ARCO and Burmah Castrol acquisitions					
Exploration and Production	14,348	11,506	9,737	6,983	5,665
Refining and Marketing	8,248	7,376	6,935	6,379	5,725
	22,596	18,882	16,672	13,362	11,390

[b]UK area includes the UK-based international activities of Refining and Marketing.

Group cash flow statement

$ million

	2000	2001	2002	2003	2004
Net cash inflow from operating activities	20,416	22,409	19,342	21,698	28,554
Dividends from joint ventures	645	104	198	131	1,908
Dividends from associated undertakings	394	528	368	417	291
Servicing of finance and returns on investments					
Interest received	444	256	231	175	332
Interest paid	(1,354)	(1,282)	(1,204)	(1,006)	(694)
Dividends received	42	132	102	140	53
Dividends paid to minority shareholders	(24)	(54)	(40)	(20)	(33)
Net cash outflow from servicing of finance and returns on investments	(892)	(948)	(911)	(711)	(342)
Taxation					
UK corporation tax	(869)	(1,058)	(979)	(1,185)	(1,447)
Overseas tax	(5,329)	(3,602)	(2,115)	(3,619)	(4,931)
Tax paid	(6,198)	(4,660)	(3,094)	(4,804)	(6,378)
Capital expenditure and financial investment					
Payments for tangible and intangible fixed assets	(8,837)	(12,142)	(12,049)	(12,368)	(13,035)
Payments for fixed assets – investments	(1,200)	(39)	(49)	(9)	–
Proceeds from the sale of fixed assets	3,029	2,365	2,470	6,253	4,323
Net cash outflow for capital expenditure and financial investment	(7,008)	(9,816)	(9,628)	(6,124)	(8,712)
Acquisitions and disposals					
Acquisitions, net of cash acquired	(6,265)	(1,210)	(4,324)	(211)	(1,503)
Proceeds from the sale of businesses	8,333	538	1,974	179	725
Acquisition of investment in TNK-BP joint venture	–	–	–	(2,351)	(1,250)
Net investment in other joint ventures	(218)	(497)	(354)	(178)	(272)
Investments in associated undertakings	(985)	(586)	(971)	(987)	(942)
Proceeds from sale of investment in Ruhrgas	–	–	2,338	–	–
Net cash (outflow) inflow from acquisitions and disposals	865	(1,755)	(1,337)	(3,548)	(3,242)
Equity dividends paid	(4,415)	(4,827)	(5,264)	(5,654)	(6,041)
Net cash inflow (outflow) before financing	3,807	1,035	(326)	1,405	6,038
Financing	3,477	1,005	(163)	1,129	6,777
Management of liquid resources	452	(211)	(220)	(41)	132
Increase (decrease) in cash	(122)	241	57	317	(871)
	3,807	1,035	(326)	1,405	6,038

Movement in net debt

$ million

	2000	2001	2002	2003	2004
Opening balance					
Finance debt	14,544	21,190	21,417	22,008	22,325
Cash	1,331	1,170	1,358	1,520	1,947
Current asset investments	220	661	450	215	185
Opening net debt	12,993	19,359	19,609	20,273	20,193
Closing balance					
Finance debt	21,190	21,417	22,008	22,325	23,091
Cash	1,170	1,358	1,520	1,947	1,156
Current asset investments	661	450	215	185	328
Closing net debt	19,359	19,609	20,273	20,193	21,607
Decrease (increase) in net debt	(6,366)	(250)	(664)	80	(1,414)
Movement in cash/bank overdrafts	(122)	241	57	317	(871)
Increase (decrease) in current asset investments	452	(211)	(220)	(41)	132
Net cash (inflow) outflow from financing (excluding share capital)	1,374	(128)	(736)	(760)	(431)
Partnership interests exchanged for BP loan notes	–	–	1,135	–	–
Debt transferred to TNK-BP	–	–	–	93	–
Exchange of Exchangeable Bonds for Lukoil American Depositary Shares	–	–	–	420	–
Other movements	(44)	(36)	76	144	68
Debt acquired	(8,072)	(55)	(1,002)	(15)	–
Movement in net debt before exchange effects	(6,412)	(189)	(690)	158	(1,102)
Exchange adjustments	46	(61)	26	(78)	(312)
Decrease (increase) in net debt	(6,366)	(250)	(664)	80	(1,414)

Consolidated statement of cash flows presented on a US GAAP format

					$ million
	2000	2001	2002	2003	2004
Operating activities					
Profit after taxation	10,209	6,617	6,872	10,652	15,961
Adjustments to reconcile profits after tax to net cash provided by operating activities					
Depreciation and amounts provided	7,526	8,858	10,401	10,940	12,583
Exploration expenditure written off	264	238	385	297	274
Net charge for pensions and other post-retirement benefits, less contributions	–	–	(178)	(2,573)	(39)
Share of (profit) loss of joint ventures and associated undertakings less dividends received	(377)	(60)	3	(532)	2
Loss (profit) on sale of businesses and fixed assets	(196)	(537)	(1,166)	(831)	(815)
Working capital movement *(see analysis below)*	(2,729)	1,399	(1,060)	(2,270)	(4,073)
Deferred taxation	1,564	1,244	1,169	1,192	200
Other	(1,657)	(191)	(383)	66	181
Net cash provided by operating activities	14,604	17,568	16,043	16,941	24,274
Investing activities					
Capital expenditures	(10,156)	(12,262)	(12,198)	(12,567)	(13,243)
Acquisitions, net of cash acquired	(6,265)	(1,210)	(4,324)	(211)	(1,503)
Acquisition of investment in TNK-BP joint venture	–	–	–	(2,351)	(1,250)
Investment in associated undertakings	(985)	(586)	(971)	(987)	(942)
Net investment in joint ventures	(218)	(497)	(354)	(178)	(272)
Proceeds from disposal of assets	11,362	2,903	6,782	6,432	5,048
Net cash used in investing activities	(6,262)	(11,652)	(11,065)	(9,862)	(12,162)
Financing activities					
Proceeds from shares issued (repurchased)	(2,103)	(1,133)	(573)	(1,889)	(7,208)
Proceeds from long-term financing	1,680	1,296	3,707	4,322	2,675
Repayments of long-term financing	(2,353)	(2,602)	(2,369)	(3,560)	(2,204)
Net increase (decrease) in short-term debt	(701)	1,434	(602)	(2)	(40)
Dividends paid					
BP shareholders	(4,415)	(4,827)	(5,264)	(5,654)	(6,041)
Minority shareholders	(24)	(54)	(40)	(20)	(33)
Net cash used in financing activities	(7,916)	(5,886)	(5,141)	(6,803)	(12,851)
Currency translation differences relating to cash and cash equivalents	(50)	(53)	90	121	91
Increase (decrease) in cash and cash equivalents	376	(23)	(73)	397	(648)
Cash and cash equivalents at beginning of year	1,455	1,831	1,808	1,735	2,132
Cash and cash equivalents at end of year	1,831	1,808	1,735	2,132	1,484
Analysis of working capital movement					
(Increase)/decrease in stocks	(1,449)	1,490	(1,521)	(841)	(3,595)
(Increase)/decrease in debtors	(5,501)	1,905	(2,445)	(3,025)	(10,770)
Increase/(decrease) in creditors	4,221	(1,996)	2,906	1,596	10,292
Total working capital movement	(2,729)	1,399	(1,060)	(2,270)	(4,073)

Capital expenditure and acquisitions

$ million

By business	2000	2001	2002	2003	2004
Exploration and Production[a]	6,365	8,853	9,659	15,370	11,193
Refining and Marketing[b,c]	8,693	2,415	7,753	3,080	3,014
Petrochemicals	1,585	1,926	823	775	2,289
Gas, Power and Renewables	394	500	448	441	538
Other businesses and corporate[d]	30,512	397	410	346	215
	47,549	14,091	19,093	20,012	17,249
By geographical area					
UK[b,e]	7,374	2,095	1,619	1,556	1,832
Rest of Europe[c]	2,041	1,787	6,556	1,277	2,105
USA[d]	34,037	6,160	6,095	6,291	6,301
Rest of World[a]	4,097	4,049	4,823	10,888	7,011
	47,549	14,091	19,093	20,012	17,249

[a]2003 includes $5,794 million for the acquisition of our interest in TNK-BP.
[b]2000 includes $4,779 million for the acquisition of Burmah Castrol.
[c]2002 includes $5,038 million for the acquisition of Veba.
[d]2000 includes $27,506 million for the acquisition of ARCO.
[e]UK area includes the UK-based international activities of Refining and Marketing.

Ratios

%

	2000	2001	2002	2003	2004
Return on average capital employed					
Replacement cost profit	14.9	10.7	7.3	12.2	15.0
Historical cost profit	15.9	8.5	8.7	12.2	16.6
(Based on profit after taxation before deducting interest expense)[a]					
Return on average BP shareholders' interest					
Replacement cost profit	18.4	13.0	8.8	15.6	19.1
Historical cost profit	19.8	10.0	10.6	15.6	21.4
(Based on profit after taxation and minority shareholders' interest)					
Payout ratio					
Replacement cost profit	49.3	58.4	94.4	55.0	45.2
Historical cost profit	45.7	75.3	79.1	54.9	40.5
(Dividend: profit)					
Debt to debt-plus-equity ratio	24.3	24.6	25.4	23.7	22.8
(Finance debt: finance debt plus BP and minority shareholders' interest)					
Debt to equity ratio	32.1	32.6	34.1	31.1	29.6
(Finance debt: BP and minority shareholders' interest)					
Net debt to net debt-plus-equity ratio	22.7	23.0	23.9	22.0	21.7
Net debt to equity ratio	29.3	29.8	31.4	28.2	27.7
(Net debt equals finance debt less cash and liquid resources)					

[a]Excludes interest on joint venture and associated undertakings' debt and is on a post-tax basis, using a deemed tax rate equal to the US statutory tax rate.

Share prices

pence

Ordinary share	2000	2001	2002	2003	2004
High	671	647	625	455	557
Daily average	579	575	512	418	489
Low	445	492	393	357	414
End year	540	534	427	453	508

$

American depositary share[a]	2000	2001	2002	2003	2004
High	60.63	54.86	53.88	49.35	61.66
Daily average	52.65	49.67	45.87	41.48	54.06
Low	43.63	43.23	36.78	35.37	47.27
End year	47.88	46.51	40.65	49.35	58.40

[a]One American depositary share (ADS) is equivalent to six 25 cent ordinary shares.

United States accounting principles

The following is a summary of adjustments to profit for the year and to BP shareholders' interest which would be required if generally accepted accounting principles in the United States (US GAAP) had been applied instead of those generally accepted in the United Kingdom (UK GAAP). The results are stated using the first-in first-out method of stock valuation.

Profit for the year (historical cost) under US GAAP — $ million

	2000	2001	2002	2003	2004
Profit for the year as reported	10,120	6,556	6,795	10,482	15,731
Adjustments					
Deferred taxation/business combinations	52	(512)	(603)	(169)	(591)
Provisions	(68)	(182)	8	49	(140)
Oil and natural gas reserve differences	–	–	–	–	30
Revisions to fair market values	–	(911)	–	289	–
Sale and leaseback	(34)	(36)	24	69	(6)
Goodwill and intangible assets	43	60	1,302	1,376	1,429
Derivative financial instruments	–	(313)	540	12	(286)
Gain arising on asset exchange	–	157	(18)	(17)	(68)
Pensions and other post-retirement benefits	–	–	50	(215)	(47)
Impairments	–	–	–	–	677
Provisions for severance and operating costs	–	–	–	–	60
Equity-accounted investments	–	–	–	–	226
Other	51	10	11	13	(43)
Profit for the year before cumulative effect of accounting change as adjusted to accord with US GAAP	10,164	4,829	8,109	11,889	16,972
Cumulative effect of accounting changes					
Provisions	–	–	–	1,002	–
Derivative financial instruments	–	(362)	–	50	–
Profit for the year as adjusted to accord with US GAAP	10,164	4,467	8,109	12,941	16,972
Dividend requirements on preference shares	2	2	2	2	2
Profit for the year applicable to ordinary shares as adjusted to accord with US GAAP	10,162	4,465	8,107	12,939	16,970
Per ordinary share – cents					
Basic – before cumulative effect of accounting changes	46.96	21.51	36.20	53.62	77.77
Cumulative effect of accounting changes	–	(1.61)	–	4.74	–
	46.96	19.90	36.20	58.36	77.77
Diluted – before cumulative effect of accounting changes	46.65	21.38	36.02	53.10	76.35
Cumulative effect of accounting changes	–	(1.60)	–	4.69	–
	46.65	19.78	36.02	57.79	76.35
Per American depositary share – cents[a]					
Basic – before cumulative effect of accounting changes	281.76	129.06	217.20	321.72	466.62
Cumulative effect of accounting changes	–	(9.66)	–	28.44	–
	281.76	119.40	217.20	350.16	466.62
Diluted – before cumulative effect of accounting changes	279.90	128.28	216.12	318.60	458.10
Cumulative effect of accounting changes	–	(9.60)	–	28.14	–
	279.90	118.68	216.12	346.74	458.10

BP shareholders' interest under US GAAP — $ million

	2000	2001	2002	2003	2004
BP shareholders' interest as reported	65,442	65,143	63,834	70,595	76,656
Adjustments					
Deferred taxation/business combinations	358	(139)	(748)	(938)	(1,533)
Provisions	(913)	(1,054)	(1,088)	(128)	(137)
Oil and natural gas reserve differences	–	–	–	–	30
Sale and leaseback	(104)	(134)	(106)	(37)	(43)
Goodwill and intangible assets	(583)	(1,414)	(84)	1,669	3,200
Derivative financial instruments	–	(675)	(135)	(72)	(361)
Gain arising on asset exchange	–	157	142	129	61
Pensions and other post-retirement benefits	(145)	(942)	3,437	5,246	5,008
Impairments	–	–	–	–	677
Provisions for severance and operating costs	–	–	–	–	60
Equity-accounted investments	–	–	–	–	226
Dividends	1,178	1,288	1,398	1,495	1,822
Investments	(112)	(2)	34	1,251	183
Other	(54)	(40)	(48)	(43)	–
BP shareholders' interest as adjusted to accord with US GAAP	65,087	62,188	66,636	79,167	85,849

[a]One American depositary share (ADS) is equivalent to six 25 cent ordinary shares.

Statistics

Crude oil, natural gas and natural gas liquids production (net of royalties)	2000	2001	2002	2003	2004
UK	534	485	462	377	330
USA	729	744	765	726	666
Other	665	702	791	1,018	1,535
Crude oil and liquids production (thousand barrels a day)	1,928	1,931	2,018	2,121	2,531
UK	1,652	1,713	1,555	1,446	1,174
USA	3,054	3,554	3,483	3,128	2,749
Other	2,903	3,365	3,669	4,039	4,580
Natural gas production (million cubic feet a day)	7,609	8,632	8,707	8,613	8,503
Total production (thousand barrels oil equivalent a day)	3,240	3,419	3,519	3,606	3,997

Refinery throughputs					thousand barrels a day
Group refinery throughputs[a]	2,916[b]	2,929	3,103	3,097	2,976
For BP by others	12	14	14	–	–
Total	2,928	2,943	3,117	3,097	2,976

Crude oil and refined petroleum product sales					thousand barrels a day
Crude oil	4,181	3,910	3,935	3,837	3,808
Refined petroleum products	5,523[c]	6,206	6,563	6,688	6,398
Total oil sales	9,704	10,116	10,498	10,525	10,206

Estimated net proved reserves of crude oil[d]					millions of barrels at 31 December
Developed	4,318	4,308	4,335	3,576	3,423
Undeveloped	2,190	2,909	3,427	3,873	4,127
Group companies	6,508	7,217	7,762	7,449	7,550
Equity-accounted entities (BP share)	1,135	1,159	1,403	2,867	3,180

Estimated net proved reserves of natural gas[e]					billions of cubic feet at 31 December
Developed	24,269	23,749	23,773	21,073	19,372
Undeveloped	16,831	19,210	22,071	22,903	23,550
Group companies	41,100	42,959	45,844	43,976	42,922
Equity-accounted entities (BP share)	2,818	3,216	2,945	2,553	2,628

Average realizations					
BP average crude oil and natural gas liquids realizations ($/bbl)	26.6	22.5	22.7	27.3	35.4
Brent oil price ($/bbl)	28.4	24.4	25.0	28.8	38.3
Henry Hub gas price ($/mmBtu)	3.9	4.3	3.2	5.4	6.1

[a] Includes crude oil and other feedstock input to BP's crude distillation units both for BP and third parties.
[b] Includes BP share of the BP/Mobil joint venture.
[c] Includes BP share of the BP/Mobil joint venture.
[d] Net proved reserves of crude oil exclude production royalties due to others.
[e] Net proved reserves of natural gas exclude production royalties due to others.

Further information is included in *BP Financial and Operating Information 2000-2004. (To obtain a copy, see page 129.)*

Employee numbers

					Year end
By business	2000	2001	2002	2003	2004
Exploration and Production	15,900	16,350	16,600	15,150	15,650
Refining and Marketing	39,500	36,100	42,050	39,200	39,300
Petrochemicals	17,600	21,950	18,950	15,950	12,400
Gas, Power and Renewables	3,500	4,400	4,600	3,750	4,050
Other businesses and corporate	3,100	2,850	2,800	2,700	3,550
Sub-total	79,600	81,650	85,000	76,750	74,950
Service station staff	27,600	28,500	30,250	26,950	27,950
	107,200	110,150	115,250	103,700	102,900
By geographical area					
UK	18,900	19,650	17,750	17,050	17,400
Rest of Europe	22,500	22,800	29,850	25,250	26,000
USA	44,000	42,750	43,200	39,100	36,950
Rest of World	21,800	24,950	24,450	22,300	22,550
	107,200	110,150	115,250	103,700	102,900

Glossary

Term used in BP Annual Report and Accounts	US equivalent or definition
Accounts	Financial statements
Acquisition accounting	Purchase accounting
Associated undertakings	Equity affiliates or investees
Called up share capital	Shares, capital stock or common stock issued and fully paid
Capital allowances	Tax depreciation
Capital redemption reserve	Other additional capital
Cash at bank	Cash
Creditors	Accounts payable and accrued liabilities
Creditors: amounts falling due within one year	Current liabilities
Creditors: amounts falling due after more than one year	Long-term liabilities
Debtors	Accounts receivable
Debtors: amounts falling due within one year	Other current assets
Debtors: amounts falling due after more than one year	Other non-current assets
Decommissioning	Dismantlement, restoration and abandonment
Employee share schemes	Employee stock benefit plans
Employment costs	Payroll costs
Finance lease	Capital lease
Financial year	Fiscal year
Fixed asset investment	Non-current investments
Freehold	Ownership with absolute rights in perpetuity
Hire charges	Rent
Interest payable	Interest expense
Interest receivable	Interest income
Joint ventures	Equity affiliates or investees
Merger accounting	Pooling of interests accounting
Net asset value	Book value
Other debtors	Other current assets
Own shares	Treasury stock
Profit	Income or earnings
Profit and loss account (statement)	Income statement
Profit and loss account *(under 'capital and reserves' in balance sheet)*	Retained earnings
Profit for year	Net income
Profit on sale of fixed assets or businesses	Gain on disposal of properties or long-term investments
Provision for doubtful debts	Allowance for doubtful accounts
Provisions	Non-current liabilities other than debt and specific accounts payable
Redundancy charges	Severance costs
Reserves	Retained earnings
Scrip dividend	Stock dividend
Shareholders' funds	Shareholders' equity
Share premium account	Amounts subscribed for share capital in excess of nominal value
Statement of total recognised gains and losses	Statement of comprehensive income
Stocks	Inventories
Tangible fixed assets	Property, plant and equipment
Turnover	Sales and other operating revenue

Governance: board performance report

Governance and the role of our board

Good governance is often defined in terms of the presence or absence of particular practices without reference to the underlying purpose of governance processes. We believe that governance is a more powerful concept.

Governance is not an exercise in compliance nor is it a higher form of management. Governance lies at the heart of all the board does and it is the task our owners entrust to the board. It has a clear objective – ensuring the pursuit of the company's purpose. The board's role is focused on this task, which is unique to it as the representative of BP's owners. This task is discharged by the board through undertaking such activities as are necessary for the effective promotion of shareholder interest.

> Governance is the system by which the company's owners and their representatives on the board ensure that it pursues, does not deviate from and only allocates resources to its defined purpose.

As a company, we recognize the importance of good governance and that it is a discrete task from management. Clarity of roles is key to our approach. Policies and processes depend upon the people who operate them. Governance requires distinct *skills* and *processes*. In the context of BP, *governance* is overseen by our board while *management* is delegated to the group chief executive by means of the board governance policies.

Our board governance policies use a coherent, principles-based approach, which anticipated many developments in UK governance regulation. They ensure that our board and management operate within a clear and efficient governance framework that goes beyond regulatory compliance and places shareholder interest at the heart of all we do.

Accountability to shareholders

Our board is accountable in a variety of ways. It is required to be proactive in obtaining an understanding of shareholder preferences and to evaluate systematically the economic, social, environmental and ethical matters that may influence or affect the interest of our shareholders.

> Our board is accountable to shareholders for the performance and activities of the entire BP group. It embeds shareholder interest in the goals established for the company.

In carrying out its work in policy-making and monitoring and in its active consideration of group strategy, our board exercises judgement on how best to further shareholder interest. The board seeks to do so by maximizing the expected value of shareholders' interest in the company, not by eliminating the possibility of any adverse outcomes.

Reporting Our board makes use of a number of formal communication channels to account to shareholders for the performance of the company. These include the Annual Report and Accounts, the Annual Review, the Annual Report on Form 20-F, quarterly Forms 6-K and announcements made through stock exchanges on which BP shares are listed, as well as through the annual general meeting (AGM).

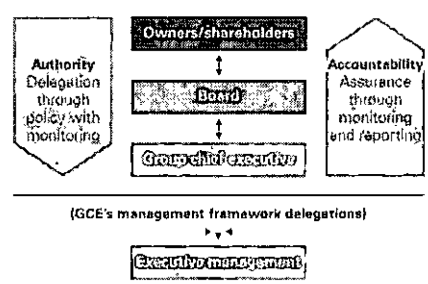
Dialogue with directors Presentations given at appropriate intervals to representatives of the investment community are available to all shareholders by internet broadcast or open conference call. Less formal processes include contacts with institutional shareholders by the chairman and other *non-executive directors*. This is supported by the dialogue with shareholders concerning the governance and operation of the group maintained by the company secretary's office, investor relations and other BP teams.

AGM and voting Given the size and geographical diversity of our shareholder base, the opportunities for shareholder interaction at the AGM are limited. However, the chairman and all board committee chairmen were present at the 2004 AGM to answer shareholders' questions and hear their views during the meeting. Members of the board met informally with shareholders afterwards. All votes at shareholder meetings, whether by proxy or in person, are counted since votes on all matters, except procedural issues, are taken by way of a poll. We have pioneered the use of electronic communications to facilitate the exercise of shareholder control rights and continue to promote the use of electronic voting through our registrar's website and through CREST.

Directors' elections Directors are required to stand for re-election each year. New directors are subject to election at the first opportunity following their appointment. All names submitted to shareholders for election are accompanied by detailed biographies.

How our board governs the company

The board's governance policies regulate its relationship with shareholders, the conduct of board affairs and the board's relationship with the group chief executive. The policies recognize the board's separate and unique role as the link in the chain of authority between the shareholders and the group chief executive. It is this unique task that gives the board its central role in governance.



The dual role played by the group chief executive and executive directors as both members *of the board* and leaders of the executive management is also recognized and addressed. The policies require a majority of the board to be composed of independent non-executive directors. To assure the integrity of the governance process, the relationship between the board and the group chief executive is governed by the non-executive directors, particularly through the work of the board committees they populate.

Recognizing that as a group its capacity is limited, our board reserves to itself the making of broad policy decisions. It delegates more detailed considerations involved in meeting its stated requirements either to board committees and officers (in the case of its own processes) or to the group chief executive (in the case of the management of the company's business activities). The board governs BP through setting general policy for the conduct of business (and critically, by clearly articulating its objective) and by monitoring its implementation by the group chief executive.

To discharge its governance function in the most effective manner, our board has laid down rules for its own activities in a *board process policy*. The board process policy covers:

- The conduct of members at meetings.
- The cycle of board activities and the setting of agendas.
- The provision of timely information to the board.
- Board officers and their roles.
- Board committees – their tasks and composition.
- Qualifications for board membership and the process of the nomination committee.
- The evaluation and assessment of board performance.
- The remuneration of non-executive directors.
- The process for directors to obtain independent advice.
- The appointment and role of the company secretary.

The responsibility for implementation of this policy is placed on the chairman.

The *board-executive linkage policy* sets out how the board delegates authority to the group chief executive and the extent of that authority. In its *goals policy*, the board states the long-term outcome and required results it expects the group chief executive to deliver. The restrictions on the manner in which the group chief executive may achieve the required results are set out in the *executive limitations policy*. This policy addresses internal control, risk preferences, financing, ethical behaviour, health, safety, the environment, treatment of employees and political considerations. Through the goals and executive limitations policies, the board shapes BP's values and standards.

Accountability in our business

Our group chief executive outlines how he intends to deliver the required outcome in annual and medium-term plans, which also address a comprehensive assessment of the group's risks. Progress towards the expected outcome forms the basis of a report to the board that covers actual results and a forecast of results for the current year. This report is reviewed at each board meeting.

The group chief executive is obliged through dialogue and systematic review to discuss with our board all material matters currently or prospectively affecting the company and its performance and all strategic projects or developments. This key dialogue specifically includes any materially under-performing business activities and actions that breach the executive limitations policy and material matters of a social, environmental and ethical nature.

The board-executive linkage policy also sets out how the group chief executive's performance will be monitored and recognizes that, in the multitude of changing circumstances, judgement is always involved. The systems set out in the board-executive linkage policy are designed to manage, rather than to eliminate, the risk of failure to achieve the board goals policy or observe the executive limitations policy. They provide reasonable, not absolute, assurance against material misstatement or loss.

Who is on the board?

The board is composed of the chairman, 12 non-executive and six executive directors. In total, five nationalities are represented on the board. Directors' biographies are set out on pages 126-127. As reported last year, the board is actively engaged in succession planning issues. As a result, the size of the board has increased during the past year despite the departure of Mr Maljers and Mr Olver. Mr Burgmans (February), Sir Tom McKillop (July) and Mr Flint (from January 2005) were appointed as non-executive directors, while Mr Conn joined the board as an executive director in July.

The efficiency and effectiveness of the board are paramount concerns. Our board is large but this is necessary to allow sufficient executive director representation to cover the breadth of the group's business activities and sufficient non-executive representation to reflect the scale and complexity of BP and to staff our board committees. A board of this size allows orderly succession planning for key roles.

Governance policies and processes depend upon the quality and commitment of the people who operate them.

New non-executive directors will be appointed over the coming years. Mr Knight and Sir Robin Nicholson will retire at the 2005 AGM. Subject to their annual re-election, Mr Miles will retire in 2006 and Mr Bryan and Mr Wilson in 2007. We believe refreshing the composition of the board should be an orderly process of evolution that ensures its continuing effectiveness.

Board independence

The qualification for board membership includes a requirement that all our non-executive directors be free from any relationship with the executive management of the company that could materially interfere with the exercise of their independent judgement. In the board's view, all our non-executive directors fulfil this requirement. It determined all 12 who served during 2004 to be independent directors.

Mr Knight and Sir Robin Nicholson were appointed to the BP board in 1987 and Mr Miles was appointed in 1994. The length of their respective service on the board exceeds the nine years referred to in the Combined Code. The board considers that the experience and long-term perspective of each of these directors on BP's business during its recent period of growth provide a valuable contribution to the board, given the long-term nature of our business. The integrity and independence of character of these directors are beyond doubt. Both Mr Knight and Sir Robin will retire at the 2005 AGM. Mr Miles will retire in 2006.

Those directors who joined the BP board in 1998 after service on the board of Amoco Corporation (Messrs Bryan, Massey, Wilson and Davis) are considered independent since the most senior executive management of BP comprises individuals who were not previously Amoco employees. While Amoco businesses and assets are a key part of the group, the scope and scale of BP since its acquisition of the ARCO, Burmah Castrol and Veba businesses are fundamentally different from those of the former Amoco Corporation.

The board has satisfied itself that there is no compromise to the independence of those directors who serve together as directors on the boards of outside entities (or who have other appointments in outside entities). Where necessary, our board ensures appropriate processes are in place to manage any possible conflict of interest.

Sir Robin Nicholson received fees during 2004 for representing the board on the BP technology advisory council. Since these fees relate to board representation, they do not compromise Sir Robin's independence. Full details of these fees are disclosed on page 125.

Directors' appointments, retirement policies and insurance

The chairman and non-executive directors of BP are elected each year and, subject to BP's Articles of Association, serve on the basis of letters of appointment. Executive directors of BP have service contracts with the company. Details of all payments to directors are reviewed in the directors' remuneration report on pages 116-125.

Annual elections for all directors and the provision of independent support to our board and board committees underscore our commitment to good governance practice.

BP's policy on directors' retirement is as follows: executive directors retire at age 60, while non-executive directors ordinarily retire at the AGM following their 70th birthday. It is the board's policy that non-executive directors are not generally expected to hold office for more than 10 years.

In accordance with BP's Articles of Association, directors are granted an indemnity from the company to the extent permitted by law in respect of liabilities incurred as a result of their office. In respect of those liabilities for which directors may not be indemnified, the company purchased and maintained a directors' and officers' liability insurance policy throughout 2004. This insurance cover was renewed at the beginning of 2005. Neither the company's indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly.

Board and committees: meetings and attendance

In addition to the AGM (which all but one director attended), the board met eight times during 2004, five times in the UK, twice in the US and once in continental Europe. Two of these meetings were two-day strategy discussions. 2004 saw an increased number of committee meetings, with no sign that this trend will reverse.

The board requires all members to devote sufficient time to the work of the board to discharge the office of director and to use their best endeavours to attend meetings. Directors' attendance at board and committee meetings is set out below. All directors attended at least 75% of meetings, except Mr Burgmans. Several board meetings coincided with commitments entered into by Mr Burgmans before his appointment to the board in February 2004, a matter made known to the board on his appointment. The board and Mr Burgmans are looking forward to his full participation in the years ahead.

Serving as a director: induction, training and evaluation

Induction Directors receive induction on their appointment to the board as appropriate, covering matters such as the operation and activities of the group (including key financial, business, social and environmental risks to the group's activities), the role of the board and the matters reserved for its decision, the tasks and membership of the principal board committees, the powers delegated to those committees, the board's governance policies and practices, and the latest financial information about the group. The chairman is accountable for the induction of new board members.

Training Our directors are updated on BP's business, the environment in which it operates and other matters throughout their period in office. We advise directors on their appointment of the legal and other duties and obligations they have as directors of a listed company. The board regularly considers the implications of these duties under our board governance policies. Our non-executive directors receive training specific to the tasks of the particular board committees on which they serve.

Outside appointments As part of their ongoing development, our executive directors are permitted to take up an external board appointment, subject to the agreement of our board. Executive directors retain any fees received in respect of such external appointments.

Generally outside appointments for executive directors are limited to one outside company board only, although our group chief executive, by exception, serves on two outside company boards. Our board is satisfied that these appointments do not conflict with his duties and commitment to BP. Non-executive directors may serve on a number of outside boards, always provided they continue to demonstrate the requisite commitment to discharge effectively their duties to BP. The nomination committee keeps the extent of directors' other interests under review to ensure that the effectiveness of our board is not compromised.

As the board attendance table below illustrates, our directors' commitment to the work of the board is manifest.

Evaluation During 2004, our board continued its ongoing evaluation processes to assess its performance and identify areas in which its effectiveness, policies or processes might be enhanced. The board reviewed the conclusions and actions from the 2003 evaluation and determined that there should be a focus on evaluating the performance of the board committees during 2004.

Directors' attendance

	Board meetings		Audit committee meetings		EEAC meetings		Chairman's committee meetings		Remuneration committee meetings		Nomination committee meetings	
	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible	Attended	Possible
P D Sutherland	7	8	–	–	–	–	3	3	7[a]	7[a]	2	2
Sir Ian Prosser	8	8	13	13	–	–	3	3	6	7	2	2
J H Bryan	8	8	13	13	–	–	3	3	2	2	–	–
A Burgmans	3	7	–	–	–	2	1	3	–	–	–	–
E B Davis, Jr	7	8	13	13	–	–	2	3	7	7	–	–
Dr D S Julius	8	8	–	–	–	–	3	3	7	7	–	–
C F Knight	7	8	–	–	–	–	3	3	6	7	–	–
Sir Tom McKillop	3	4	–	–	–	–	2	2	2	2	–	–
F A Maljers	3	3	–	–	2	2	1	1	–	–	–	–
Dr W E Massey	8	8	–	–	6	6	3	3	–	–	2	2
H M P Miles	8	8	12	13	6	6	3	3	–	–	–	–
Sir Robin Nicholson	8	8	–	–	–	–	3	3	7	7	2	2
M H Wilson	8	8	13	13	6	6	3	3	–	–	–	–
Lord Browne	8	8	–	–	–	–	–	–	–	–	–	–
Dr D C Allen	8	8	–	–	–	–	–	–	–	–	–	–
I C Conn	4	4	–	–	–	–	–	–	–	–	–	–
Dr B E Grote	8	8	–	–	–	–	–	–	–	–	–	–
Dr A B Hayward	8	8	–	–	–	–	–	–	–	–	–	–
J A Manzoni	8	8	–	–	–	–	–	–	–	–	–	–
R L Olver	4	4	–	–	–	–	–	–	–	–	–	–

[a] Attended all remuneration committee meetings as chairman of the board.

Regular evaluation of board effectiveness underpins our confidence in BP's governance policies and processes and affords opportunity for their development.

Evaluations of both the audit and the ethics and environment assurance committees took place during the year. An evaluation of the work of the remuneration committee will take place this year as the review of executive remuneration is concluded and Dr Julius assumes chairmanship of the committee. Work on a further evaluation of the board and the performance of individual directors has commenced.

The chairman and senior independent director

BP's board governance policies require the chairman and deputy chairman to be non-executive directors; throughout 2004 the posts were held by Mr Sutherland and Sir Ian Prosser respectively. Sir Ian also acts as our *senior independent director* and is the director whom shareholders may contact if they feel their concerns are not being addressed through normal channels.

Between board meetings, the *chairman* has responsibility for ensuring the integrity and effectiveness of the board/executive relationship. This requires his interaction with the group chief executive between board meetings, as well as his contact with other board members and shareholders. The chairman represents the views of the board to shareholders on key issues, not least in succession planning issues for both executive and non-executive appointments. The chairman and all the non-executive directors meet periodically as the *chairman's committee (see report on page 114)*. The performance of the chairman is evaluated each year at a meeting of the chairman's committee, for which item of business he is not present. The company secretary reports to the chairman and is not part of the executive management.

Board committees

The board process policy allocates the tasks of monitoring executive actions and assessing performance to certain board committees. These tasks, rather than any terms of reference, prescribe the authority and the role of the board committees. Reports for each of the committees for 2004 appear below. In common with the board, each committee has access to independent advice and counsel as required and each is supported by the company secretary and his office, which is demonstrably independent of the executive management of the group.

Audit committee report

Schedule and composition The committee met 13 times during 2004 and comprised the following directors: *Sir Ian Prosser (chairman), J H Bryan, E B Davis, Jr, H M P Miles, M H Wilson.*

All members of the audit committee are independent non-executive directors. The board considers that the membership of the audit committee as a whole has sufficient recent and relevant financial experience to discharge its functions, but it has determined not to identify any single member as having such experience. The external auditors' lead partner, the BP general auditor (head of internal audit), together with the group chief financial officer, the chief accounting officer and the group controller, attend each meeting at the request of the committee chairman. At least twice a year, the committee meets with the external auditor without the executive management being present. The committee also meets in private session with the general auditor.

Role and authority The audit committee's tasks are considered by the committee to be broader than those envisaged under Combined Code Provision C.3.2. The committee is satisfied that it addresses each of those matters identified as properly falling within an audit committee's purview. The committee has full delegated authority from the board to address those tasks assigned to it. In common with the board and all committees, it may request any information from the executive management necessary to discharge its functions and may, where it considers necessary, seek independent advice and counsel.

Process The committee structures its work programme so as to discharge its tasks, which include systematic monitoring and obtaining assurance that the legally required standards of disclosure are being fully and fairly observed and that the executive limitations relating to financial matters are being observed. The committee chairman reports on the committee's activities to the board meeting immediately following a committee meeting. Between meetings, the committee chairman reviews emerging issues with the group chief financial officer, the external auditor and the BP general auditor. He is supported in this task by the company secretary's office.

During the year, external specialist legal and regulatory advice has also been provided to the committee by Sullivan & Cromwell LLP. With significant changes in accounting practices being introduced in 2005, the committee undertook initial training in the implementation of International Financial Reporting Standards (IFRS) and how these standards are expected to affect the group's reported results.

Activities in 2004 *Financial reports:* During the year, the committee reviewed all annual and quarterly financial reports before recommending their publication on behalf of the board. In particular, the committee discussed significant accounting policies, estimates and judgements that had been applied in preparing these reports and received independent advice from the external auditors.

Accounting treatment: The committee also received during the year separate reports concerning the group's environmental and decommissioning provisions, tax exposures, pension assumptions and the status of current litigation. The committee gained assurance that such liabilities and contingencies were appropriately reflected in the financial results.

System of internal control: Each year, specific reports on risk management and internal control within selected business and functional activities are considered. During 2004, the exploration and production and petrochemicals segments were reviewed, along with accounting issues of the supply and trading function that services all BP's businesses. Given the increased public and regulatory attention to hydrocarbon reserves reporting, the committee sought and received additional assurance that BP's management and recording processes are applied in a consistent and coherent manner throughout the group. Following the adoption of the US Sarbanes-Oxley Act of 2002, an increased regulatory requirement has been placed on all companies that offer shares by listing on US stock exchanges. The committee has monitored the company's response to the applicable requirements of this Act and, in particular, its progress in evaluating internal controls as required by rules pursuant to Section 404 of the Act.

Employee concerns reporting/whistleblowing: The committee receives regular reports of the matters raised through the employee concerns programme (OpenTalk) and, through this process, is alerted to instances of potential fraud or matters of concern raised related to the finances and financial accounting policies of the group.

Auditor independence and rotation: The committee reviews on behalf of the board the independence, objectivity and viability of the auditors before an appointment recommendation is made to shareholders at the AGM. A new lead audit partner is appointed every five years and other senior audit staff are rotated every seven years.

Policy on non-audit services provided by the auditor: To safeguard the independence of the audit process, non-audit services provided by the auditor are limited to defined audit-related work and tax services that fall within specific categories. Additionally, all such services must be pre-approved by the committee. These services have been substantially reduced in 2004 but overall fees paid to Ernst & Young have increased, since audit fees have risen significantly across the market due to the increased regulatory burden on listed companies *(see page 50 for details)*.

Internal audit: The committee considers the internal auditor's programme and its effectiveness twice a year. It receives regular reports of work undertaken, actions recommended and the executive management's responses to those recommendations.

Performance evaluation: Each year the committee critically reviews its own performance and considers where improvements can be made. During 2004, the committee strengthened its tracking of outstanding issues and clarified the scope of its role and relationship with that of the ethics and environment assurance committee. It also allocated additional time to training, not least on the implications of the introduction of IFRS. To accommodate all such matters and discharge its ongoing tasks the committee increased the number of meetings from nine in 2003 to 13 in 2004.

Ethics and environment assurance committee report

Schedule and composition The committee met six times during 2004 and comprised the following directors: *Dr W E Massey (chairman), A Burgmans (from October 2004), F A Maljers (to April 2004), H M P Miles, M H Wilson.*

All members of the ethics and environment assurance committee are independent non-executive directors. The external auditors' lead partner and the BP general auditor (head of internal audit) attend each meeting at the request of the committee chairman. The committee met once during 2004 with the general auditor and external auditor but without the executive management being present.

Role and authority The task of the committee is to monitor matters relating to the executive management's processes to address environmental, health and safety, security and ethical behaviour issues. The committee monitors the observance of the executive limitations relating to non-financial risks to the group.

Process and activities in 2004 At each meeting, the committee considered a report from executive management on current developments in business and functional areas giving rise to ongoing and emergent non-financial risks to the group's activities. In particular, during the course of 2004, the committee directed its attention to the BTC pipeline project and operations in Alaska and Russia. The committee's work programme also addressed:

Environmental liabilities: Including a review of the group's approach to remediation at operational and disused sites, encompassing all businesses ranging from mining activities to oil terminals to service stations.

Health, safety and environmental performance: Greenhouse gas and other emissions, spills and containment practices and safety at work issues, both group-wide and in specific businesses and locations (for example, shipping, road safety and the operational integrity of plant and equipment).

Security: Group preparedness and mitigation plans in respect of identified and potential security threats to staff, physical infrastructure and the digital infrastructure of the group.

Employees: The results of the annual People Assurance Survey, employee health and welfare and the impact of HIV/AIDS on our business.

Ethical behaviour: Matters arising from the annual ethics certification process and OpenTalk (BP's employee concerns reporting programme), as well as other conduct and compliance issues.

Disaster recovery and business continuity planning and capability: Development of the group's capacity and capability to respond to catastrophic events and to maintain its business activities.

Performance evaluation: The committee addressed the nature of its remit and authority, its interface with the audit committee and the scope and focus of its activities, as well as its overall effectiveness and refinements to its processes. The committee increased the number of its meetings from five in 2003 to six in 2004.

Remuneration committee report

Schedule and composition The committee met seven times during 2004 and comprised the following directors: *Sir Robin Nicholson (chairman, retiring at the 2005 AGM), Dr D S Julius (chairman elect), E B Davis, C F Knight (retiring at the 2005 AGM), Sir Ian Prosser, J H Bryan (from November 2004), Sir Tom McKillop (from November 2004).*

All members of the remuneration committee are non-executive directors and are considered by the board to be independent. The chairman of the board also attends committee meetings. The committee is independently advised.

Role and authority The committee's main task is to determine the terms of engagement and remuneration of the executive directors. A key priority for the committee in 2004 has been its review of executive directors' remuneration policy in preparation for the renewal of the long-term incentive plan for executive directors at the 2005 AGM.

Process and activities in 2004 Full details of the committee's remit and work are set out in the remuneration report on pages 116-125, which is the subject of a vote by shareholders at the forthcoming AGM.

Chairman's committee report

Schedule and composition The chairman's committee met three times during 2004 and comprised all the non-executive directors.

Role and authority The task of the committee is to consider broad issues of governance, including the performance of the chairman and the group chief executive, succession planning, the organization of the group and any matters referred to it for an opinion from another board committee.

Process and activities in 2004 At its various meetings, the committee evaluated the performance of the chairman and the group chief executive, considered the plan for executive succession and considered a number of other broad matters of governance, including the future governance of the Olefins and Derivatives business as it is prepared for its planned disposal. Additionally, the committee addressed non-executive succession planning issues in co-ordination with the nomination committee.

Nomination committee report

Schedule and composition The committee met twice during 2004 and comprised the following directors: *P D Sutherland (chairman), Dr W E Massey, Sir Robin Nicholson, Sir Ian Prosser.*
All members of the nomination committee are considered by the board to be independent.

Role and authority The task of the nomination committee is to identify and evaluate candidates for appointment and reappointment as director or company secretary of BP.

Process During the year, the nomination committee carried out a detailed review of the skills and expertise of the non-executive directors as part of the board succession planning described earlier. The committee receives external assistance as required. The committee consults with the group chief executive concerning the identification and appointment of new executive directors.

Activities in 2004 The committee considered the composition of the board and board committees in the context of forthcoming work programmes, BP's strategy and business activities and retirements from the board. Board and committee evaluation processes informed its work in identifying the skills and experiences sought from potential candidates.

External search consultants were retained in the UK, continental Europe and the US to assist the committee in the identification of potential candidates as non-executive directors. In close co-ordination with the chairman's committee (all the non-executive directors), the nomination committee recommended the appointment of the following directors during the year: Sir Tom McKillop, I C Conn and D J Flint.

Combined Code compliance

BP complied throughout 2004 with the provisions of the Combined Code Principles of Good Governance and Code of Best Practice, except in the following aspects:

A.4.4 Letters of appointment do not set out fixed time commitments since the schedule of board and committee meetings is subject to change according to the exigencies of the business. All directors are expected to demonstrate their commitment to the work of the board on an ongoing basis. This is reviewed by the nomination committee in recommending candidates for annual re-election.

B.1.4 The amount of fees received by executive directors in respect of their service on outside boards is not disclosed since this information is not considered relevant to BP.

B.2.3 The remuneration of the chairman is fixed by the board as a whole (rather than by the remuneration committee) within the limits set by shareholders, since the chairman's performance is a matter for the whole board.

Internal control review

The board governance policies include a process for the board to review regularly the effectiveness of the system of internal control as required by Code provision C.2.1. As part of this process, the board, the audit and the ethics and environment assurance committees requested, received and reviewed reports from executive management, including management of the principal business segments, at their regular meetings. That enabled them to assess the effectiveness of the system of internal control in operation for managing significant risks (including social, environmental and ethical risks) throughout the year. This process did not extend to joint ventures or associates.

The executive management presented reports to the January and February 2005 meetings of both the audit and the ethics and environment assurance committees to support the board in its annual assessment of internal control. The reports described how significant risks were identified and embedded within business segment and function plans across the group. They reviewed the executive management's assurance process and the continuing development of the systems of internal controls in place to identify, address and manage risks. The reports also highlighted future potentially significant risks to the company's plans. The two committees engage with executive management on a regular basis to monitor the management of these risks. Significant incidents that occurred and management's response to them were considered by the committees during the year.

In the board's view, the information it received was sufficient to enable it to review the effectiveness of the company's system of internal control in accordance with the Guidance for Directors on Internal Control (Turnbull).

Directors' interests

in BP ordinary shares or calculated equivalents

	At 31 Dec 2004	At 1 Jan 2004 or on appointment	Change from 31 Dec 2004-8 Feb 2005
Current directors (excluding director appointed in 2005)			
Dr D C Allen	408,342[a]	371,365[a]	–
Lord Browne	2,031,279[b]	1,816,054[b]	–
J H Bryan	158,760[c]	158,760[c]	–
A Burgmans	10,000	10,000[d]	–
I C Conn	121,187	119,098[e]	71
E B Davis, Jr	66,349[c]	65,162[c]	–
Dr B E Grote	888,213[c]	788,313[c]	–
Dr A B Hayward	206,084	121,692	71
Dr D S Julius	15,000	15,000	–
C F Knight	98,578[c]	95,610[c]	–
Sir Tom McKillop	20,000	–[e]	–
J A Manzoni	196,336	127,821	68
Dr W E Massey	49,722[c]	49,261[c]	–
H M P Miles	22,145	22,145	–
Sir Robin Nicholson	4,020	3,897	–
Sir Ian Prosser	16,301	16,301	–
P D Sutherland	30,079	30,079	–
M H Wilson	60,000[c]	60,000[c]	–

	At retirement	At 1 Jan 2004
Directors leaving the board in 2004		
F A Maljers	33,492[c]	33,492[c]
R L Olver	884,408	798,326

	On appointment 1 January 2005	Change from 1 Jan 2005-7 Feb 2005
Director appointed in 2005		
D J Flint	–	–

[a] Includes 25,368 shares held as ADSs.
[b] Includes 50,368 shares held as ADSs.
[c] Held as ADSs.
[d] On appointment at 5 February 2004.
[e] On appointment at 1 July 2004.

In disclosing the above interests to the company under the Companies Act 1985, directors did not distinguish their beneficial and non-beneficial interests.

Executive directors are also deemed to have an interest in such shares of the company held from time to time by BP QUEST Company Limited and The BP Employee Share Ownership Plan (No. 2) to facilitate the operation of the company's option schemes.

No director has any interest in the preference shares or debentures of the company, or in the shares or loan stock of any subsidiary company.

Directors' remuneration report

The directors' remuneration report covers all directors, both executive and non-executive, and is set out on pages 116-125.

It is divided into two parts. Executive directors' remuneration is in the first part, which was prepared by the remuneration committee.

Non-executive directors' remuneration is in the second part, which was prepared by the company secretary on behalf of the board.

The report has been approved by the board and signed on its behalf by the company secretary. This report is subject to the approval of shareholders at the annual general meeting (AGM).

Part 1 – Executive directors' remuneration

Dear Shareholder

2004 was a good year. Company results, as explained elsewhere, were excellent and the remuneration committee's priority on relating pay to performance is reflected in the annual bonus payments commensurate with this high level of achievement. These and all other aspects of the executive directors' remuneration during the year are set out in detail in the committee's report that follows.

The committee also undertook a comprehensive and independent review of remuneration policy for the executive directors during 2004, prior to seeking your approval for the renewal of the long-term incentive plan at this year's AGM *(resolution 23)*. As part of this review, we commissioned significant and wide-ranging academic research and sought the views of major shareholders in an effort to consider the fundamental bases underlying our remuneration policies and practices. The depth and extensive nature of this review have meant that our policy and practices are underpinned by a strong set of principles, which guide the committee's deliberations. Full details of these are set out in the report.

Measures of performance lie at the heart of any performance-based system and we have, with extensive advice and considerable time, examined different approaches. While there is no perfect measure, we believe the selected quantitative and qualitative measures are the most appropriate for BP. Given the inherent imperfections of any measure of performance, we also see the use of our judgement as an integral part of the process. We recognize that our relationship with you is built on trust, and we are clear that it is important for us to be transparent in our explanations to you of how we have reached decisions and exercised our discretion.

We have an excellent team of world-class executive directors leading the company. The remuneration decisions we have taken for 2004 appropriately reflect the high level of performance achieved during the year. The policy we have set out for the future should continue to align their remuneration with shareholders' interests as well as to engage them in pursuing long-term shareholder value.

Sir Robin Nicholson
Chairman, Remuneration Committee
7 February 2005

Dr D S Julius
Chairman elect, Remuneration Committee

The remuneration committee

Tasks The committee's tasks are:

- To determine on behalf of the board the terms of engagement and remuneration of the group chief executive and the executive directors and to report on those to the shareholders.
- To determine on behalf of the board matters of policy over which the company has authority relating to the establishment or operation of the company's pension scheme of which the executive directors are members.
- To nominate on behalf of the board any trustees (or directors of corporate trustees) of such scheme.
- To monitor the policies being applied by the group chief executive in remunerating senior executives other than executive directors.

Constitution and operation The committee members are all non-executive directors. Sir Robin Nicholson (chairman), Mr Davis, Dr Julius, Mr Knight and Sir Ian Prosser were members of the committee throughout the year, with Sir Tom McKillop and Mr Bryan joining them in November 2004. Sir Robin Nicholson and Mr Knight will both be retiring at the 2005 AGM and Dr Julius will become the committee chairman. Each member is now subject to annual re-election as a director of the company. The board considers all committee members to be independent *(see page 111)*. They have no personal financial interest, other than as shareholders, in the committee's decisions. The committee met seven times in the period under review. There was a full attendance record, except that Sir Ian Prosser and Mr Knight were each unable to attend one meeting. Mr Sutherland, as chairman of the board, has attended all committee meetings.

The committee is accountable to shareholders through its annual report on executive directors' remuneration. It will consider the outcome of the vote at the AGM on the remuneration report, and the views of shareholders will be taken into account by the committee in its future decisions. The committee values its dialogue with major shareholders on remuneration matters.

Advice Advice is provided to the committee by the company secretary's office, which is independent of executive management and reports to the chairman of the board. Mr Aronson, an independent consultant, is the committee's secretary and special adviser. Advice was also received from Mr Jackson (company secretary) and Mrs Martin (senior counsel, company secretary's office).

The committee also appoints external professional advisers to provide specialist advice and services on particular remuneration matters. The independence of advice is subject to annual review.

In 2004, the committee consulted three independent academics, Michael Jensen, professor emeritus of Harvard Business School, and professors Sir Andrew Likierman and James Dow, both of London Business School, in connection with its fundamental review of remuneration policy.

The committee appointed Towers Perrin as its principal external adviser during 2004. Towers Perrin also provided limited ad hoc remuneration and benefits advice to parts of the group, mainly comprising pensions advice in Canada, as well as providing some market information on pay structures. The committee also appointed Kepler Associates to advise on performance measurement. Kepler Associates also provided performance data and limited ad hoc advice on performance measurement to the group.

Freshfields Bruckhaus Deringer and Martin Moore, QC, have provided legal advice on specific matters to the committee. Freshfields Bruckhaus Deringer also provided some legal advice, principally overseas, to subsidiaries in the group.

Ernst & Young, in their capacity as auditors, reviewed the calculations in respect of financial-based targets that form the basis of the performance-related pay for the executive directors. They also provided audit, audit-related and taxation services to the group.

Lord Browne (group chief executive) was consulted on matters relating to the other executive directors who report to him and, together with Dr Allen (group chief of staff), on matters relating to the performance of the company. Neither was present when matters affecting his own remuneration were considered.

Policy on executive directors' remuneration

A key priority for the committee in 2004 has been its comprehensive and independent review of all elements of remuneration policy for executive directors prior to seeking specific shareholder approval for renewal of the Executive Directors' Incentive Plan, which expires in 2005. This wide-ranging review sought to address the fundamental bases of the remuneration policies and plans for the executive directors. It involved significant academic research as well as seeking the views of plan participants, major shareholders and professional advisers. The committee focused on seeking to ensure that, in determining remuneration policy, there is a clear link between the company's purpose, the business plans and executive reward.

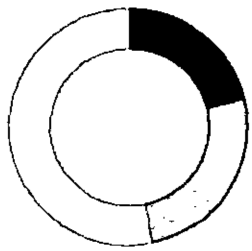
As part of its review, the committee developed the following key principles to guide its policy:

- Policy for the remuneration of executive directors shall be determined and regularly reviewed independently of executive management and will set the tone for the remuneration of other senior executives.
- The remuneration structure shall support and reflect BP's stated purpose to maximize long-term shareholder value.
- The remuneration structure shall reflect a just system of rewards for the participants.
- The overall quantum of all potential remuneration components shall be determined by the exercise of informed judgement of the independent remuneration committee, taking into account the success of BP and the competitive global market.
- The majority of the remuneration shall be linked to the achievement of demanding performance targets that are independently set and reflect the creation of long-term shareholder value.
- Assessment of performance shall be quantitative and qualitative and shall include exercise of informed judgement by the remuneration committee within a framework that takes account of sector characteristics and is approved by shareholders.
- The committee shall be proactive in obtaining an understanding of shareholder preferences.
- Remuneration policy and practices shall be as transparent as possible both for participants and shareholders.

Key policy decisions The committee then reviewed the existing remuneration policies and plans against these principles and made the following key policy decisions:

- The overall quantum of remuneration and the general balance between short-term and long-term elements are to be maintained.
- Salary levels will continue to be reviewed regularly by reference to those in Europe-based top global companies and the US oil and gas sector applying the committee's judgement.
- The long-term incentives framework of the existing Executive Directors' Incentive Plan (EDIP) remains sound, although some changes to policy and application are now appropriate. Specific shareholder approval is being sought for renewal of the EDIP for a further five years.
- The share element of the EDIP will provide the long-term performance-based component of the executive directors' remuneration package. There is no current intention to make further share options grants.
- The majority of the value previously attributed to share options is to be redistributed to the share element, with the remainder going to the annual bonus.
- The measure of long-term performance for the share element will be relative total shareholder return (TSR) compared with the other oil majors over three-year periods, with underlying relative performance also being assessed by the committee.
- A proportion of the share element for the current group chief executive will be based on long-term personal leadership measures.
- To simplify the operation of the EDIP and increase transparency, the share element will use performance shares rather than the current performance units and multiples.
- The performance shares will accrue dividends during the performance period.
- The current shareholding requirement for executive directors is to be maintained at 5 x the director's base salary, to ensure alignment of their interests with those of shareholders.
- The current pension approach based on national policies is to be maintained.
- The wider scene, including pay and employment conditions elsewhere in the group, will be taken into account, especially when determining annual salary increases.

Elements of remuneration The executive directors' total remuneration will continue to consist of salary, annual bonus, long-term incentives, pensions and other benefits. This reward structure will be regularly reviewed by the committee to ensure that it is achieving its objectives. In 2005, over three-quarters of executive directors' potential direct remuneration will again be performance-related *(see illustrative chart on page 118)*.



This chart reflects on-target values for annual bonus and share element.

Salary The committee expects to review salaries in 2005. In doing so, the committee considers both Europe-based top global companies and the US oil and gas sector; each of these groups is defined and analysed by the committee's independent external remuneration advisers. The committee then assesses the market information and advice and applies its judgement in setting the salary levels.

Annual bonus Each executive director is eligible to participate in an annual performance-based bonus scheme. The committee reviews and sets bonus targets and levels of eligibility annually.

For 2005, the target level will be increased from 100% to 120% of base salary (except for Lord Browne, for whom, as group chief executive, it is considered appropriate to increase his target from 110% to 130%). These increases reflect part of the value previously attributed to the share option element of their remuneration packages. In normal circumstances, the maximum payment level for substantially exceeding targets will continue to be 150% (165% for the group chief executive) of base salary. In exceptional circumstances, outstanding performance may be recognized by bonus payments moderately in excess of the 150% (and 165%) levels at the discretion of the remuneration committee. Similarly, bonuses may be reduced where the committee considers that this is warranted and, in exceptional circumstances, bonuses can be reduced to zero.

The committee recognizes that it is responsible to shareholders to use its discretion in a reasonable and informed manner in the best interests of the company and that it has a corresponding duty to be accountable and transparent as to the manner in which it exercises its discretion. The committee will explain any significant exercise of discretion in the subsequent directors' remuneration report.

The key aim of the revised annual bonus is to ensure that it is closely tied to the annual business plan and that it reflects short-term deliverables towards the creation of long-term shareholder value.

Executive directors' annual bonus awards for 2005 will be based on a mix of demanding financial targets, based on the company's annual plan and leadership objectives established at the beginning of the year, in accordance with the following weightings:

- 50% financial measures from the annual plan principally on cash flow.
- 30% annual strategic metrics and milestones taken from the five-year group business plan. There is a wide range of measures, including those relating to people, safety, environment, technology and organization, as well as operational actions and business development.
- 20% individual performance against leadership objectives and living the values of the group which incorporates BP's code of conduct.

In assessing the final outcome of the individual bonuses each year, the committee will also carefully review the underlying performance of the group in the context of the five-year group business plan, as well as looking at competitor results, analysts' reports and the views from the chairmen of other BP board committees. All the calculations are reviewed by the auditors.

Long-term incentives Long-term incentives will continue to be provided under the EDIP. It will continue to have within its framework three elements: a share element, a share option element and a cash element. The committee does not currently intend to use either the share option or cash elements but, in exceptional circumstances, may do so.

Each executive director participates in the EDIP. The committee's policy, subject to unforeseen circumstances, is that this should continue until the EDIP expires or is renewed in 2010.

The committee's policy continues to be that each executive director should hold shares equivalent in value to 5 x the director's base salary within five years of being appointed an executive director. This policy is reflected in the terms of the EDIP, as shares awarded under the share element will only be released at the end of the three-year retention period *(as described below)* if the minimum shareholding guidelines have been met.

1 Share element The committee may make conditional share awards (performance shares) to executive directors, which will only vest to the extent that a demanding performance condition imposed by the committee is met at the end of a three-year performance period. As explained above, for 2005 and future years, the committee currently intends that the share element alone will provide the long-term performance-based component of the executive directors' package, and award levels have been adjusted to reflect this.

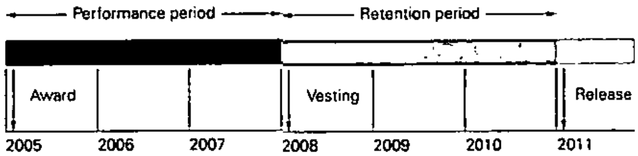
Share element awards have been made in 2001 to 2004 inclusive using performance units that may convert into ordinary shares at a ratio of up to two shares for each performance unit *(full details of which are set out on page 123)*. To simplify the operation of the plan and increase transparency, the award of performance shares will, for 2005 and future years, replace performance units. Vesting of performance shares will be at a maximum ratio of one-for-one. This change will not increase the value of the award levels or make performance conditions easier to achieve.

The maximum number of performance shares that may be awarded to an executive director in any one year will be determined at the discretion of the remuneration committee and will not normally exceed 5.5 x base salary and, in the case of the group chief executive, 7.5 x base salary.

In addition to the performance condition described below, the committee will have an overriding discretion, in exceptional circumstances, to reduce the number of shares which vest (or to provide that no shares vest).

The shares which vest will normally be subject to a compulsory retention period determined by the committee, which will not normally be less than three years. This gives executive directors a six-year incentive structure, and is designed to ensure that their interests are aligned with those of shareholders. Where shares vest under awards made in 2005 and future years, the executive director will receive additional shares representing the value of reinvested dividends on these shares.

Timeline for 2005-2007 EDIP share element



For share element awards in 2005, the performance condition will relate to BP's total shareholder return (TSR) performance against the other oil majors (ExxonMobil, Shell, Total and ChevronTexaco) over a three-year period. TSR is calculated by taking the share price performance of a company over the period, assuming dividends to be reinvested in the company's shares. All share prices will be averaged over the three months before the beginning and end of the performance period and will be measured in US dollars. At the end of the performance period, the TSR performance of each of the companies will be ranked to establish the relative total return to shareholders over the period. Shares under the award will vest as to 100%, 70% and 35% if BP achieves first, second or third place respectively; no shares will vest if BP achieves fourth or fifth place.

Extensive research was independently commissioned by the committee into alternative measures of business performance. After careful review of the studies, the committee is satisfied that relative TSR is the most appropriate measure of performance for BP's long-term incentives for executive directors as it best reflects the creation of long-term shareholder value. Relative performance of the peer group is particularly key in order to minimize the influence of sector-specific effects, including oil price.

The committee is convinced that this comparator group, while small, has the distinct advantage of being very clearly comprised of BP's global competitors. Consultation with major shareholders confirmed that this is the group already used by most of them, as well as by management, in assessing BP's comparative performance. The committee will have the discretion to amend this peer group in appropriate circumstances, for example, in the case of any significant consolidations in the industry.

The committee is mindful of the possibility that a simple ranking system may in some circumstances give rise to distorted results in view of the broad similarity of the oil majors' underlying businesses, the small size of the comparator group and inherent imperfections in measurement. To counter this, the committee will have the ability to exercise discretion in a reasonable and informed manner to adjust (upwards or downwards) the vesting level derived from the ranking if it considers that the ranking does not fairly reflect BP's underlying business performance relative to the comparator group.

The exercise of this discretion would be made after a broad analysis of the underlying health of BP's business relative to competitors, as shown by a range of other measures including, but not limited to, return on average capital employed, earnings per share growth, reserves replacement and cash flow. This will enable a more comprehensive review of long-term performance, with the aims of tempering anomalies created by relying solely on a formula-based approach and ensuring that the objectives of the plan are met.

It is anticipated that the need to use discretion is most likely to arise where the TSR performance of some companies is clustered, so that a relatively small difference in TSR performance would produce a major difference in vesting levels. In these circumstances, the committee will have power to adjust the vesting level, normally by determining an average vesting level for the companies affected by the clustering.

In line with its policy on transparency, the committee will explain any adjustment to the relative TSR ranking in the next directors' remuneration report following the vesting.

The committee may amend the performance conditions if events occur that would make the amended condition a fairer measure of performance and provided that any amended condition is no easier to satisfy.

For 2005, all executive directors will receive performance share awards on the above basis, over a maximum number of shares set by reference to 5.5 x base salary. For awards under the share element in future years, the committee may continue with the same performance condition, or may impose a different condition which it considers to be no less demanding.

As group chief executive, Lord Browne is eligible for performance share awards of up to 7.5 x base salary. The committee has determined that, while the largest part of this should relate to the TSR measure described above, it is appropriate that a specific part (up to 2 x base salary) should be based on long-term leadership measures. These will focus on sustaining BP's financial, strategic and organizational health and will include, but not be limited to, maintenance of BP's performance culture and the continued development of BP's business strategy, executive talent and internal organization. As with the TSR part of his award, this part will be measured over three-year performance periods.

Share element awards made in previous years

For outstanding awards of performance units made under the plans for the periods 2002-2004, 2003-2005 and 2004-2006, the existing performance conditions will apply for the three-year performance periods in each of the plans. The primary measure is BP's shareholder return against the market (SHRAM), which accounts for nearly two-thirds of the potential total award, the remainder being assessed on BP's relative return on average capital employed (ROACE) and earnings per share growth (EPS).

BP's SHRAM is measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS growth are measured against ExxonMobil, Shell, Total and ChevronTexaco. All calculations are reviewed by the auditors to ensure that they meet an independent objective standard. The relative position of the company within the comparator group determines the number of shares awarded per performance unit, subject to a maximum of two shares per unit.

2. Share option element The share option element of the EDIP permits options to be granted to executive directors at an exercise price no lower than the market value of a share at the date the option is granted. The committee does not currently intend to use this element.

3. Cash element The cash element allows the committee to grant long-term cash-based incentives. This element was not used during the first five years of the EDIP and the committee would only do so in special circumstances.

Pensions Executive directors are eligible to participate in the appropriate pension schemes applying in their home countries.

UK directors UK directors are members of the regular BP Pension Scheme. Scheme members' core benefits are non-contributory. They include a pension accrual of 1/60th of basic salary for each year of service, subject to a maximum of two-thirds of final basic salary; and a dependant's benefit of two-thirds of the member's pension. Bonuses are not pensionable for UK directors. The scheme pension is not integrated with state pension benefits.

Normal retirement age is 60, but scheme members who have 30 or more years' pensionable service at age 55 can elect to retire early without an actuarial reduction being applied to their pension.

In accordance with the company's past practice for executive directors who retire from BP on or after age 55 having accrued at least 30 years' service, Lord Browne remains eligible for consideration for a payment from the company of an ex-gratia lump-sum superannuation payment equal to one year's base salary following his retirement. All matters relating to such superannuation payments are considered by the remuneration committee. Any such payment would be additional to his pension entitlements referred to above. No other executive director is eligible for consideration for a superannuation payment on retirement, as the remuneration committee decided in 1996 that appointees to the board after that time should cease to be eligible for consideration for such a payment.

The UK government has announced important proposals on pensions, the impact of which will be reviewed further by the committee in 2005 in conjunction with studies being carried out by the company into the wider effects of the new legislation for employees. The intention is that the approach to the new legislation should be consistent for directors and other employees. The committee will report further on the outcome of these studies in the next remuneration report.

US director Dr Grote as a US director participates in the US BP Retirement Accumulation Plan (US plan), which features a cash balance formula. The current design of the US plan became effective on 1 July 2000.

Consistent with US tax regulations, pension benefits are provided through a combination of tax-qualified and non-qualified benefit restoration plans, as applicable.

The Supplemental Executive Retirement Benefit (supplemental plan) is a non-qualified top-up arrangement that became effective on 1 January 2002 for US employees above a specified salary level.

The benefit formula is 1.3% of final average earnings, which comprise base salary and bonus in accordance with standard US practice (as specified under the qualified arrangement) multiplied by years of service, with an offset for benefits payable under all other BP qualified and non-qualified pension arrangements. This benefit is unfunded and therefore paid from corporate assets.

Dr Grote is an eligible participant under the supplemental plan, and his pension accrual for 2004 includes the total amount that may become payable under all plans.

Other benefits

- Benefits and other share schemes: Executive directors are eligible to participate in regular employee benefit plans and in all-employee share schemes and savings plans applying in their home countries. Benefits in kind are not pensionable.
- Resettlement allowance: Expatriates may receive a resettlement allowance for a limited period.

Service contracts

Director	Contract date	Current salary
Lord Browne	11 November 1993	£1,415,600
Dr D C Allen	29 January 2003	£420,000
I C Conn	22 July 2004	£400,000
Dr B E Grote	7 August 2000	$900,000
Dr A B Hayward	29 January 2003	£420,000
J A Manzoni	29 January 2003	£420,000
Director leaving the board in 2004		
R L Olver	31 December 1997	

The committee's policy is for service contracts to expire at normal retirement date and have a notice period of one year. All contracts comply with this.

The service contracts of Dr Allen, Dr Hayward, Mr Manzoni and Mr Conn may also be terminated by the company at any time with immediate effect on payment in lieu of notice equivalent to one year's salary or the amount of salary that would have been paid if the contract had terminated on the expiry of the remainder of the notice period.

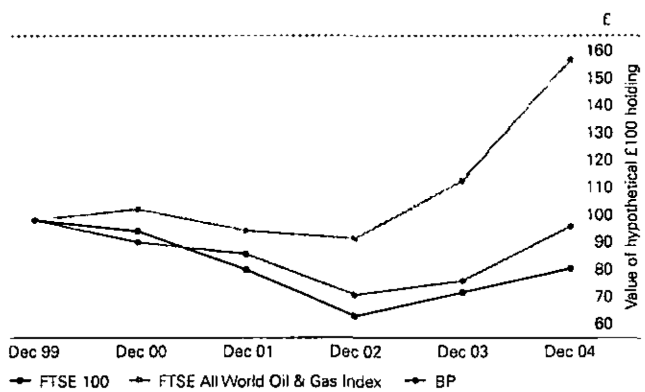
Dr Grote's service contract is with BP Exploration (Alaska) Inc. He is seconded to BP p.l.c. under a secondment agreement dated 7 August 2000 that had an unexpired term of three years at 31 December 2004. The secondment may be terminated by one month's notice by either party and terminates automatically on the termination of Dr Grote's service contract.

There are no other provisions for compensation payable on early termination of the above contracts. In the event of early termination under any of the above contracts by the company other than for cause (or under a specific termination payment provision), the relevant director's then current salary and benefits would be taken into account in calculating any liability of the company.

Since January 2003, the committee has included a provision in new service contracts to allow for severance payments to be phased, where appropriate to do so. It will also consider mitigation to reduce *compensation to a departing director, where appropriate to do so.*

Historical TSR performance

This graph is included to meet a legislative requirement and shows the growth in the value of a hypothetical £100 holding in BP p.l.c. ordinary shares over five years relative to the FTSE 100 and to the FTSE All World Oil & Gas Index. These are considered to be the most relevant broad equity market indices for this purpose and the company is a constituent of both indices.



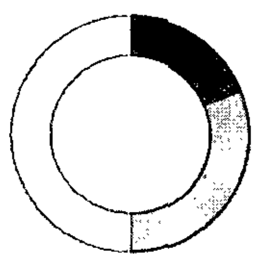
Information subject to audit

Summary of 2004 remuneration

	Annual remuneration								Long-term remuneration					
									Share element of EDIP/LTPPs				Grants under EDIP	
									2002-2004 plan (to be awarded in Feb 2005)		2001-2003 plan (awarded in Feb 2004)		(granted in Feb 2004)	
	Salary (thousand)		Annual performance bonus (thousand)		Non-cash benefits & other emoluments (thousand)		Total (thousand)		Expected award[a] (shares)	Value[b] (thousand)	Actual award (shares)	Value[c] (thousand)	2004-2006 share element[d] (performance units)	Share option element[e] (options)
	2003	2004	2003	2004	2003	2004	2003	2004						
Lord Browne	£1,316	£1,382	£1,882	£2,280	£79	£82	£3,277	**£3,744**	356,667	£1,905	352,750	£1,457	634,447	1,500,000
Dr D C Allen	£367	£410	£459	£615	£2	£11	£828	**£1,036**	60,000	£320	62,518	£258	188,235	275,000
I C Conn[f]	n/a	£200	n/a	£300	n/a	£42	n/a	**£542**	51,750	£276	n/a	n/a	n/a	n/a
Dr B E Grote	$770	$841	$1,001	$1,262	$179[g]	–	$1,950	**$2,103**	136,960	$1,381	131,750	$1,053	212,669	349,998
Dr A B Hayward	£367	£410	£459	£615	£3	£36	£829	**£1,061**	55,125	£294	54,825	£226	188,235	275,000
J A Manzoni[h]	£367	£410	£477	£615	£34	£46	£878	**£1,071**	60,000	£320	51,170	£211	188,235	275,000
Director leaving the board in 2004														
R L Olver[i]	£570	£292	£741	£438	£43	£42	£1,354	**£772**	147,222	£786	144,500	£597	n/a	n/a

Amounts shown are in the currency received by executive directors. Annual bonus is shown in the year it was earned.

[a] Gross award of shares based on a performance assessment by the remuneration committee and on the other terms of the plan. Sufficient shares are sold to pay for tax applicable. Remaining shares are held in trust for current directors until 2008, when they are released to the individual.
[b] Based on closing price of BP shares on 3 February 2005 (£5.34 per share/$60.49 per ADS).
[c] Based on average market price on date of award (£4.13 per share/$47.96 per ADS).
[d] Performance units granted under the 2004-2006 share element of the EDIP are converted to shares at the end of the performance period. Maximum of two shares per performance unit.
[e] Options granted in February 2004 have a grant price of £4.22 per share. Dr Grote holds options over ADSs; the above numbers reflect calculated equivalents.
[f] Reflects remuneration received by Mr Conn since appointment as executive director on 1 July 2004.
[g] Includes resettlement allowance for Dr Grote of $175,000, which expired in 2003.
[h] Mr Manzoni also received compensation of £50,000 in 2004 relating to expatriate costs prior to his appointment as an executive director.
[i] Amounts for Mr Olver reflect the period until his retirement on 1 July 2004.



2004 actual remuneration elements

- Base salary
- Performance-related annual bonus
- Performance-related long-term incentives include a share element and share options

This chart reflects the average mix of total remuneration received by executive directors in 2004 and includes actual salary, bonus and share element award as well as a Black Scholes value of options granted.

Salary Following a review of appropriate comparator groups of Europe-based top global companies and the US oil and gas sector, base salaries for Lord Browne, Dr Allen, Dr Hayward and Mr Manzoni were increased by 5% per annum with effect from 1 July 2004. *On his appointment to the board in 2004, Mr Conn's salary was* determined by reference to the same comparator groups.

In deciding upon these new salary levels the committee applied its judgement, taking into account the modest market movements in Europe and the US and the fact that no salary increases had been received by the three executive directors appointed in February 2003 since that time.

Dr Grote's salary was increased in the context of the comparative market information by approximately 15% with effect from 1 July 2004 to reflect his expanded senior role following the retirement of Mr Olver.

Annual bonus Fifty per cent of the annual bonus awards for 2004 is based on a mix of financial targets (primarily cash from operations) and 50% is based on long-run metrics and wide-ranging milestones that drive performance improvement and measure the continuing delivery of strategy (including production and sales levels, efficiency, cost management, business development, project delivery and technology progress). All the targets were established at the beginning of the year by the remuneration committee. 2004 was an extremely good year. The group met or exceeded its annual plan in all material respects. The primary financial target, cash from operations, was exceeded. All the key metrics and milestones were delivered, along with some notable successes in relation to Russia and exploration in Egypt and the Gulf of Mexico. Assessment of all the results, including those on people, *safety, environment and organization, resulted in awards of 150% of* salary for the executive directors. The committee determined that, given the year's excellent performance, it was appropriate that Lord Browne receive 165% of salary, reflecting his higher bonus target level. All calculations have been reviewed by the auditors.

Share options

	Option type	At 1 Jan 2004	Granted	Exercised	At 31 Dec 2004	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Lord Browne	SAYE	4,550	–	–	4,550	£3.50	–	1 Sept 2008	28 Feb 2009
	EDIP	408,522	–	–	408,522	£5.99	–	15 May 2001	15 May 2007
	EDIP	1,269,843	–	–	1,269,843	£5.67	–	19 Feb 2002	19 Feb 2008
	EDIP	1,348,032	–	–	1,348,032	£5.72	–	18 Feb 2003	18 Feb 2009
	EDIP	1,348,032	–	–	1,348,032	£3.88	–	17 Feb 2004	17 Feb 2010
	EDIP	–	1,500,000	–	1,500,000	£4.22	–	25 Feb 2005	25 Feb 2011
Dr D C Allen	EXEC	37,000	–	–	37,000	£5.99	–	15 May 2003	15 May 2010
	EXEC	87,950	–	–	87,950	£5.67	–	23 Feb 2004	23 Feb 2011
	EXEC	175,000	–	–	175,000	£5.72	–	18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88	–	17 Feb 2004	17 Feb 2010
	EDIP	–	275,000	–	275,000	£4.22	–	25 Feb 2005	25 Feb 2011
Dr B E Grote[a]	SAR	40,800	–	40,800	–	$16.63	$48.67	25 Mar 1997	25 Mar 2004
	SAR	35,600	–	35,600	–	$19.16	$61.60	28 Feb 1998	28 Feb 2005
	SAR	35,200	–	–	35,200	$25.27	–	6 Mar 1999	6 Mar 2006
	SAR	40,000	–	–	40,000	$33.34	–	28 Feb 2000	28 Feb 2007
	BPA	10,404	–	–	10,404	$53.90	–	15 Mar 2000	14 Mar 2009
	BPA	12,600	–	–	12,600	$48.94	–	28 Mar 2001	27 Mar 2010
	EDIP	40,182	–	–	40,182	$49.65	–	19 Feb 2002	19 Feb 2008
	EDIP	58,173	–	–	58,173	$48.82	–	18 Feb 2003	18 Feb 2009
	EDIP	58,173	–	–	58,173	$37.76	–	17 Feb 2004	17 Feb 2010
	EDIP	–	58,333	–	58,333	$48.53	–	25 Feb 2005	25 Feb 2011
Dr A B Hayward	SAYE	3,302	–	–	3,302	£5.11	–	1 Sept 2006	28 Feb 2007
	EXEC	34,000	–	–	34,000	£5.99	–	15 May 2003	15 May 2010
	EXEC	77,400	–	–	77,400	£5.67	–	23 Feb 2004	23 Feb 2011
	EXEC	160,000	–	–	160,000	£5.72	–	18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88	–	17 Feb 2004	17 Feb 2010
	EDIP	–	275,000	–	275,000	£4.22	–	25 Feb 2005	25 Feb 2011
J A Manzoni	SAYE	750	–	750	–	£4.50	£5.04	1 Sept 2004	28 Feb 2005
	SAYE	878	–	–	878	£4.52	–	1 Sept 2007	28 Feb 2008
	SAYE	2,548	–	–	2,548	£3.50	–	1 Sept 2008	28 Feb 2009
	SAYE	–	847	–	847	£3.86	–	1 Sept 2009	28 Feb 2010
	EXEC	12,000	–	–	12,000	£2.04	–	28 Feb 1998	28 Feb 2005
	EXEC	34,000	–	–	34,000	£5.99	–	15 May 2003	15 May 2010
	EXEC	72,250	–	–	72,250	£5.67	–	23 Feb 2004	23 Feb 2011
	EXEC	175,000	–	–	175,000	£5.72	–	18 Feb 2005	18 Feb 2012
	EDIP	220,000	–	–	220,000	£3.88	–	17 Feb 2004	17 Feb 2010
	EDIP	–	275,000	–	275,000	£4.22	–	25 Feb 2005	25 Feb 2011
Director appointed to the board in 2004									
I C Conn	SAYE	1,050[b]	–	1,050	–	£4.50	£5.04	1 Sept 2004	28 Feb 2005
	SAYE	1,355[b]	–	–	1,355	£4.98	–	1 Sept 2005	28 Feb 2006
	SAYE	1,456[b]	–	–	1,456	£3.50	–	1 Sept 2008	28 Feb 2009
	SAYE	–	1,186	–	1,186	£3.86	–	1 Sept 2009	28 Feb 2010
	EXEC	900[b]	–	–	900	£5.67	–	23 Feb 2004	23 Feb 2011
	EXEC	71,350[b]	–	–	71,350	£5.67	–	23 Feb 2004	23 Feb 2011
	EXEC	4,356[b]	–	–	4,356	£5.72	–	18 Feb 2005	18 Feb 2012
	EXEC	125,644[b]	–	–	125,644	£5.72	–	18 Feb 2005	18 Feb 2012
	EXEC	160,000[b]	–	–	160,000	£3.88	–	17 Feb 2006	17 Feb 2013
	EXEC	126,000[b]	–	–	126,000	£4.22	–	25 Feb 2007	25 Feb 2014
Director leaving the board in 2004									
R L Olver	SAYE	2,642	–	–	2,642[c]	£3.50	–	1 Sept 2006	28 Feb 2007
	EDIP	71,847	–	–	71,847[c]	£5.99	–	15 May 2001	15 May 2007
	EDIP	260,319	–	–	260,319[c]	£5.67	–	19 Feb 2002	19 Feb 2008
	EDIP	370,956	–	–	247,304[c,d]	£5.72	–	18 Feb 2003	18 Feb 2009
	EDIP	370,956	–	–	123,652[c,d]	£3.88	–	17 Feb 2004	17 Feb 2010
	EDIP	–	400,000	–	–[c,d]	£4.22	–	–	–

The closing market prices of an ordinary share and of an ADS on 31 December 2004 were £5.08 and $58.40 respectively. During 2004, the highest market prices were £5.56 and $62.10 respectively, and the lowest market prices were £4.13 and $46.65 respectively.

EDIP = Executive Directors' Incentive Plan adopted by shareholders in April 2000 as described on pages 118-119. The grants were made taking into consideration the ranking of the company's TSR against the TSR of the FTSE Global 100 group of companies over the three-year period prior to the grant.

BPA = BP Amoco share option plan, which applied to US executive directors prior to the adoption of the EDIP.

SAR = Stock Appreciation Rights under BP America Inc. Share Appreciation Plan. In keeping with the US market practice, none of the options under the BPA and SAR is subject to performance conditions because they were granted under American plans to the relevant individuals.

SAYE = Save As You Earn employee share option scheme. These options are not subject to performance conditions because this is an all-employee share scheme governed by specific tax legislation.

EXEC = Executive Share Option Scheme. These options were granted to the relevant individuals prior to their appointments as directors and are not subject to performance conditions.

[a] Numbers shown are ADSs under option. One ADS is equivalent to six ordinary shares.

[b] On appointment to the board of BP p.l.c. on 1 July 2004.

[c] On leaving the board of BP p.l.c. on 1 July 2004.

[d] Remaining options after deduction of those that lapsed on retirement.

Share element of EDIP and Long Term Performance Plans (LTPPs)
Under the share element of the EDIP and the Long Term Performance Plans, performance units were granted at the beginning of the three-year period and converted into an award of shares at the end of the period, depending on performance. There is a maximum of two shares per performance unit. For 2005 and future years, a different grant mechanism will apply *(as described on page 118)*.

For the 2002-2004 share element of the EDIP and the LTPPs, BP's performance was assessed in terms of SHRAM, ROACE and EPS growth. BP's three-year SHRAM was measured against the companies in the FTSE All World Oil & Gas Index. Companies within the index are weighted according to their market capitalization at the beginning of each three-year period in order to give greatest emphasis to oil majors. BP's ROACE and EPS were measured against ExxonMobil, Shell, Total and ChevronTexaco. Based on a performance assessment of 75 points out of 200 (0 for SHRAM, 50 for ROACE and 25 for EPS growth), the committee expects to make awards of shares to executive directors as highlighted in the 2002-2004 lines of the table below.

Share element of EDIP and LTPPs

				Share element/LTPP interests			Interests vested in 2004		
				Performance units[b]					
	Performance period[a]	Date of grant of performance units	Market price of each share at date of grant of performance units £	At 1 Jan 2004	Granted 2004	At 31 Dec 2004	Number of ordinary shares awarded[c]	Share award date	Market price of each share at share award date £
Lord Browne	2001–2003	19 Feb 2001	5.80	415,000	–	–	352,750	12 Feb 2004	4.13
	2002–2004	**18 Feb 2002**	**5.73**	**475,556**	–	**475,556**	**356,667**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	632,512	–	632,512	–	–	–
	2004–2006	25 Feb 2004	4.25	–	634,447	634,447	–	–	–
Dr D C Allen	2001–2003	12 Mar 2001	5.88	73,550	–	–	62,518	12 Feb 2004	4.13
	2002–2004	**6 Mar 2002**	**5.99**	**80,000**	–	**80,000**	**60,000**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	197,044	–	197,044	–	–	–
	2004–2006	25 Feb 2004	4.25	–	188,235	188,235	–	–	–
Dr B E Grote	2001–2003	19 Feb 2001	5.80	155,000	–	–	131,750	12 Feb 2004	4.13
	2002–2004	**18 Feb 2002**	**5.73**	**182,613**	–	**182,613**	**136,960**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	233,638	–	233,638	–	–	–
	2004–2006	25 Feb 2004	4.25	–	212,669	212,669	–	–	–
Dr A B Hayward[d]	2001–2003	12 Mar 2001	5.88	64,500	–	–	54,825	12 Feb 2004	4.13
	2002–2004	**6 Mar 2002**	**5.99**	**73,500**	–	**73,500**	**55,125**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	197,044	–	197,044	–	–	–
	2004–2006	25 Feb 2004	4.25	–	188,235	188,235	–	–	–
J A Manzoni[d]	2001–2003	12 Mar 2001	5.88	60,200	–	–	51,170	12 Feb 2004	4.13
	2002–2004	**6 Mar 2002**	**5.99**	**80,000**	–	**80,000**	**60,000**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	197,044	–	197,044	–	–	–
	2004–2006	25 Feb 2004	4.25	–	188,235	188,235	–	–	–
Director appointed to the board in 2004									
I C Conn	2001–2003	12 Mar 2001	5.88	60,200[e]	–	–	51,170	12 Feb 2004	4.13
	2002–2004	**6 Mar 2002**	**5.99**	**69,000[e]**	–	**69,000**	**51,750**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	91,000[e]	–	91,000	–	–	–
	2004–2006	25 Feb 2004	4.25	–	91,000	91,000	–	–	–
Director leaving the board in 2004									
R L Olver	2001–2003	19 Feb 2001	5.80	170,000	–	–	144,500	12 Feb 2004	4.13
	2002–2004	**18 Feb 2002**	**5.73**	**196,296**	–	**196,296[f]**	**147,222**	**expected award Feb 2005**	
	2003–2005	17 Feb 2003	3.96	274,138	–	274,138[f]	–	–	–
Past directors									
R F Chase	2001–2003	19 Feb 2001	5.80	205,000	–	–	174,250	12 Feb 2004	4.13
	2002–2004	**18 Feb 2002**	**5.73**	**237,037**	–	**237,037**	**177,778**	**expected award Feb 2005**	
	2002–2004	**13 Mar 2002**	**6.17**	**34,994**	–	**34,994**	**26,245**	**expected award Feb 2005**	
Dr J G S Buchanan	1998-2000	5 Feb 1998	4.05	159,000	–		351,453[g]	12 Feb 2004	4.13
	2001-2003	19 Feb 2001	5.80	165,000	–		140,250	12 Feb 2004	4.13
	2002-2004	**18 Feb 2002**	**5.73**	**192,593**	–	**192,593**	**144,445**	**expected award Feb 2005**	
	2002-2004	**13 Mar 2002**	**6.17**	**28,433**	–	**28,433**	**21,325**	**expected award Feb 2005**	
W D Ford	2001–2003	19 Feb 2001	5.80	170,000	–	–	144,500	12 Feb 2004	4.13

[a] Dr Allen, Dr Hayward and Mr Manzoni continue to have performance units for the performance periods 2001-2003 and 2002-2004 granted under LTPPs, and Mr Conn for the periods 2001-2003 to 2004-2006 inclusive. They are not required to relinquish these rights, which were granted prior to their appointments as executive directors. All other units were granted under the EDIP as explained on pages 118-119. BP's performance is assessed against the oil sector. For 1998-2000, BP's SHRAM was measured against ExxonMobil, Shell, Total and ChevronTexaco. For 2001-2003, BP's SHRAM, ROACE and EPS growth were measured against ExxonMobil, Shell, Total, ChevronTexaco, ENI and Repsol. For 2004-2006, BP's SHRAM is measured against companies in the All World Oil & Gas Index and BP's ROACE and EPS growth against ExxonMobil, Shell, Total and ChevronTexaco. Each performance period ends on 31 December of the third year.
[b] Represents number of performance units, each having a maximum potential of two shares depending on performance.
[c] Represents awards of shares made or expected to be made at the end of the relevant performance period based on performance achieved under rules of the plan.
[d] Dr Hayward and Mr Manzoni elected to defer to 2005 the determination of whether LTPP awards should be made for the 1999-2001 performance period. As this period ended prior to their appointment as directors, the expected awards are not included in the table.
[e] On appointment to the board of BP p.l.c. on 1 July 2004.
[f] On leaving the board of BP p.l.c. on 1 July 2004.
[g] Dr Buchanan elected to defer to 2004 the determination of whether an award should be made for the 1998-2000 period. This number includes dividends.

Pensions

thousand	Service at 31 Dec 2004	Accrued pension entitlement at 31 Dec 2004	Additional pension earned during the year ended 31 Dec 2004	Transfer value of accrued benefit[a] at 31 Dec 2003 (A)	Transfer value of accrued benefit[a] at 31 Dec 2004 (B)	Amount of B-A less contributions made by the director in 2004
Lord Browne (UK)	38 years	£944	£45	£13,921	£15,189	£1,268
Dr D C Allen (UK)	26 years	£183	£15	£2,089	£2,264	£175
I C Conn (UK)	19 years	£127	£35	£849	£1,217	£368
Dr B E Grote (US)	25 years	$465	$94	$4,814	$5,529	$715
Dr A B Hayward (UK)	23 years	£188	£18	£1,967	£2,255	£288
J A Manzoni (UK)	21 years	£149	£14	£1,395	£1,595	£200
Director leaving the board in 2004						
R L Olver (UK)[b]	31 years	£390	–	£6,271	£9,098	£2,827

[a]Transfer values have been calculated in accordance with version 8.1 of guidance note GN11 issued by the actuarial profession.
[b]Mr Olver retired on 1 July 2004 and elected to take a lump sum of £905,194 in lieu of part of his entitlement. The figures in the table include the allowance for this lump sum.

Past directors

Following his retirement from BP p.l.c., Mr Olver was appointed on 1 July 2004 as a consultant to BP in relation to its activities in Russia. He had previously been appointed as a BP-nominated director of TNK-BP Limited, a joint venture company owned 50% by BP, effective 20 April 2004. Under the consultancy agreement, he received £150,000 in fees in 2004 and, as a director, deputy chairman and chairman of the audit committee of the joint venture company, he received $90,000 in fees from TNK-BP Limited.

Mr Chase's consultancy to BP in relation to the TNK-BP transaction ended in May 2004 and he left the board of TNK-BP Limited in March 2004. Under the consultancy agreement, he received $250,000 in 2004 and as a director, deputy chairman and chairman of the audit committee of TNK-BP Limited he received $30,000 in fees from that company.

Long-term awards for both former directors of BP p.l.c. are in accordance with scheme rules and are outlined in the table on page 123.

Part 2 – Non-executive directors' remuneration

Policy on non-executive directors' remuneration

The board sets the level of remuneration for all non-executive directors within the limit approved from time to time by shareholders. In line with BP's governance policies, by the remuneration of the chairman is set by the board rather than by the remuneration committee, since the performance of the chairman is a matter for the board as a whole rather than any one committee.

The board has adopted the following policies to guide its current and future decision-making with regard to non-executive directors' remuneration.

- Within the limits set by the shareholders from time to time, remuneration should be sufficient to attract, motivate and retain world-class non-executive talent.
- Remuneration of non-executive directors is set by the board and should be proportional to their contribution towards the interests of the company.
- Remuneration practice should be consistent with recognized best-practice standards for non-executive directors' remuneration.
- Remuneration should be in the form of cash fees, payable monthly.
- Non-executive directors should not receive share options from the company.
- Non-executive directors should be encouraged to establish a holding in BP shares broadly related to one year's base fee, to be held directly or indirectly in a manner compatible with their personal investment activities, and any applicable legal and regulatory requirements.

Elements of remuneration

Non-executive directors' pay comprises cash fees, paid monthly, with increments for positions of additional responsibility, reflecting additional workload and consequent potential liability. For all non-executive directors, except the chairman, a fixed sum allowance is paid for transatlantic travel undertaken for the purpose of attending a board or board committee meeting. In addition, non-executive directors receive reimbursement of reasonable travel and related business expenses. No share or share option awards are made to any non-executive director in respect of service on the board.

Letters of appointment

Non-executive directors have letters of appointment, which recognize that, subject to the Articles of Association, their service is at the discretion of the shareholders. All directors stand for re-election at each annual general meeting.

Non-executive directors' annual fee structure

The fees paid to non-executive directors are set by the board within the limit set by shareholders in accordance with the Articles. Shareholders approved an increase to this limit at the 2004 AGM. All fees are fixed and paid in pounds sterling. Fees payable to non-executive directors were last adjusted during 2002.

	£ thousand
Chairman	390[a]
Deputy chairman	85[b]
Board member	65
Committee chairmanship fee	15
Transatlantic attendance allowance[c]	5

[a] The chairman is not eligible for committee chairmanship fees or transatlantic attendance allowance but has the use of a fully maintained office for company business and a chauffeured car.
[b] The deputy chairman receives a £20,000 increment on top of the standard board fee. In addition, he is eligible for committee chairmanship fees and the transatlantic attendance allowance. The deputy chairman is currently chairman of the audit committee.
[c] This allowance is payable to non-executive directors undertaking transatlantic travel for the purpose of attending a board meeting or board committee meeting.

Long-term incentives (residual)

The table in the right-hand column sets out the residual entitlements of non-executive directors who were formerly non-executive directors of Amoco Corporation under the Amoco Non-Employee Directors' Restricted Stock Plan.

Information subject to audit

Remuneration of non-executive directors

Current directors	2004	2003
J H Bryan	100	95
A Burgmans[a]	53	n/a
E B Davis, Jr	105	90
Dr D S Julius	75	80
C F Knight	90	95
Sir Tom McKillop[b]	38	n/a
Dr W E Massey	115	110
H M P Miles	75	80[c]
Sir Robin Nicholson[d]	90	95
Sir Ian Prosser	110	115
P D Sutherland	390	390
M H Wilson	95	95
Director leaving the board in 2004		
F A Maljers[e]	16	80

£ thousand

[a] Appointed on 5 February 2004.
[b] Appointed on 1 July 2004.
[c] Also received £600 in 2003 for serving as a director of BP Pension Trustees Limited. These fees are no longer payable to BP non-executive directors.
[d] Also received £20,000 each year for serving as the board's representative on the BP technology advisory council.
[e] Retired at AGM on 15 April 2004.

Amoco Non-Employee Directors' Restricted Stock Plan

Non-executive directors of Amoco Corporation were allocated restricted stock in the Amoco Non-Employee Directors' Restricted Stock Plan by way of remuneration for their service on the board of Amoco Corporation prior to its merger with BP in 1998. On merger, interests in Amoco shares in the plan were converted into interests in BP ADSs. Under the terms of the plan, the restricted stock will vest upon the retirement of the non-executive director having reached age 70 or upon earlier retirement at the discretion of the board. Since the merger, no further entitlements have accrued to any director under the plan. These residual interests require disclosure under the directors' remuneration report regulations 2002 as interests in a long-term incentive scheme.

	Interest in BP ADSs at 1 January 2004 and 31 December 2004[a]	Date on which director reaches age 70[b]
J H Bryan	5,546	5 October 2006
E B Davis, Jr	4,490	5 August 2014
Dr W E Massey	3,346	5 April 2008
M H Wilson	3,170	4 November 2007
Director leaving the board in 2004		
F A Maljers[c]	2,906	12 August 2003

[a] No awards were granted and no awards lapsed during the year.
[b] For the purposes of the regulations, the date on which the director retires from the board at or after the age of 70 is the end of the qualifying period. If the director retires prior to this date, the board may waive the restrictions.
[c] Mr Maljers retired from the board on 15 April 2004 and, in accordance with the terms of the plan, his awards vested on that date (when the BP ADS closing price was $54.16) without payment by him. These awards over BP ADSs derived from awards over Amoco shares granted between 26 April 1994 and 28 April 1998. The awards were granted over Amoco stock prior to the merger but their notional weighted average market value at the date of grant (applying the subsequent merger ratio of 0.66167 of a BP ADS for every Amoco share) was $27.87 per BP ADS.

Superannuation gratuities

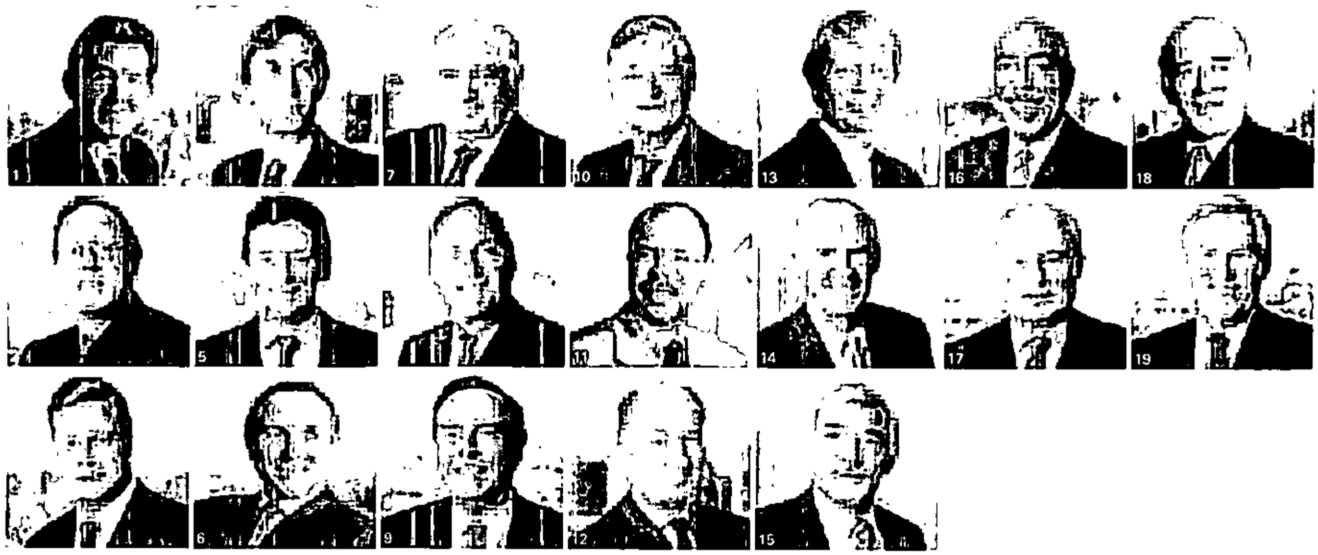
In accordance with the company's long-standing practice, non-executive directors who retire from the board after at least six years' service are, at the time of their retirement, eligible for consideration for a superannuation gratuity. The board is authorized to make such payments under the company's Articles. The amount of the payment is determined at the board's discretion (having regard to the director's period of service as a director and other relevant factors).

In 2002, the board revised its policy with respect to such payments so that: (i) non-executive directors appointed to the board after 1 July 2002 would not be eligible for consideration for such a payment; and (ii) while non-executive directors in service at 1 July 2002 would remain eligible for consideration for a payment, service after that date would not be taken into account by the board in considering the amount of any such payment.

The board made no superannuation gratuity payments during the year.

This directors' remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary, on 7 February 2005.

Board of directors



Executive directors

1 The Lord Browne of Madingley, FREng
Group Chief Executive
Lord Browne (56) joined BP in 1966 and subsequently held a variety of exploration and production and finance posts in the US, UK and Canada. He was appointed an executive director in 1991 and group chief executive in 1995. He is a non-executive director of Intel Corporation and Goldman Sachs. He was knighted in 1998 and made a life peer in 2001.

2 **Dr D C Allen,** Group Chief of Staff
David Allen (50) joined BP in 1978 and subsequently undertook a number of corporate and exploration and production roles in London and New York. He moved to BP's corporate planning function in 1986, becoming group vice president in 1999. He was appointed an executive vice president and group chief of staff in 2000 and an executive director of BP in 2003.

3 **I C Conn,** Group Executive Officer, Strategic Resources
Iain Conn (42) joined BP in 1986. Following a variety of roles in oil trading, refining, commercial marketing, exploration and production, in 2000 he became group vice president of BP's refining and marketing business. From 2002 to 2004, he was chief executive of petrochemicals. He was appointed group executive officer with a range of regional and functional responsibilities and an executive director in July 2004. He was appointed to the board of Rolls-Royce Group plc in January 2005.

4 **Dr B E Grote,** Chief Financial Officer
Byron Grote (56) joined BP in 1987 following the acquisition of The Standard Oil Company of Ohio, where he had worked since 1979. He became group treasurer in 1992 and in 1994 regional chief executive in Latin America. In 1999, he was appointed an executive vice president of exploration and production, and chief executive of chemicals in 2000. He was appointed an executive director of BP in 2000 and chief financial officer in 2002.

5 **Dr A B Hayward,** Chief Executive, Exploration and Production
Tony Hayward (47) joined BP in 1982. He became a director of exploration and production in 1997, the segment in which he had previously held a series of roles. In 2000, he was made group treasurer and an executive vice president in 2002. He was appointed chief operating officer for exploration and production in 2002 and an executive director of BP in 2003. He is a non-executive director of Corus Group.

6 **J A Manzoni,** Chief Executive, Refining and Marketing
John Manzoni (45) joined BP in 1983. He became group vice president for European marketing in 1999 and BP regional president for the eastern US in 2000. In 2001, he became an executive vice president and chief executive for gas and power. He was appointed chief executive of refining and marketing in 2002 and an executive director of BP in 2003. He is a non-executive director of SABMiller plc.

Non-executive directors

7 **P D Sutherland, KCMG**
Chairman
Peter Sutherland (58) rejoined BP's board in 1995, having been a non-executive director from 1990 to 1993, and was appointed chairman in 1997. He is non-executive chairman of Goldman Sachs International and a non-executive director of Investor AB and The Royal Bank of Scotland Group plc.

Chairman of the chairman's and nomination committees

8 **Sir Ian Prosser,** Deputy Chairman
Sir Ian (61) joined BP's board in 1997 and was appointed non-executive deputy chairman in 1999. He retired as chairman of InterContinental Hotels Group PLC, previously Bass PLC, in 2003. He was a non-executive director of The Boots Company from 1984 to 1996, of Lloyds Bank PLC from 1988 to 1995 and of Lloyds TSB Group PLC from 1995 to 1999. In 1999, he was appointed a non-executive director of GlaxoSmithKline and in 2004 he was appointed a non-executive director of Sara Lee Corporation.

Member of the chairman's, nomination and remuneration committees and chairman of the audit committee

9 J H Bryan
John Bryan (68) joined BP's board in 1998, having previously been a director of Amoco. He serves on the boards of General Motors Corporation and Goldman Sachs. He retired as chairman of Sara Lee Corporation in 2001. He is chairman of Millennium Park Inc. in Chicago.

Member of the chairman's, remuneration and audit committees

10 A Burgmans
Antony Burgmans (58) joined BP's board in 2004. He was appointed to the board of Unilever in 1991. In 1999, he became chairman of Unilever NV and vice chairman of Unilever PLC. He is also a member of the supervisory board of ABN AMRO Bank NV.

Member of the chairman's and ethics and environment assurance committees

11 E B Davis, Jr
Erroll B Davis, Jr (60) joined BP's board in 1998, having previously been a director of Amoco. He is chairman and chief executive officer of Alliant Energy, a member of the advisory board of the Federal Reserve Bank of Chicago and a non-executive director of PPG Industries, Union Pacific Corporation and the US Olympic Committee.

Member of the chairman's, audit and remuneration committees

12 D J Flint
Douglas Flint (49) joined BP's board in January 2005. He trained as a chartered accountant and became a partner at KPMG in 1988. In 1995, he was appointed group finance director of HSBC Holdings plc. He is chairman of the Financial Reporting Council's review of the Turnbull Guidance on Internal Control. Between 2001 and 2004, he served on the Accounting Standards Board and the advisory council of the International Accounting Standards Board.

13 Dr D S Julius, CBE
DeAnne Julius (55) joined BP's board in 2001. She began her career as a project economist with the World Bank in Washington. From 1986 until 1997, she held a succession of posts, including chief economist at British Airways and Royal Dutch Shell Group. From 1997 to 2001, she was a full-time member of the Monetary Policy Committee of the Bank of England. She is chairman of the Royal Institute of International Affairs and a non-executive director of Lloyds TSB Group PLC, Serco and Roche Holdings SA.

Member of the chairman's and remuneration committees and chairman elect of the remuneration committee

14 C F Knight
Charles Knight (69) joined BP's board in 1987. He was employed by Lester B Knight and Associates of Chicago, consulting engineers, from 1961 to 1973. In 1972, he joined Emerson Electric Co., became chairman in 1974 and retired in 2004. He is a non-executive director of Anheuser-Busch, Morgan Stanley Dean Witter, SBC Communications and IBM.

Member of the chairman's and remuneration committees

15 Sir Tom McKillop
Sir Tom McKillop (61) joined BP's board in July 2004. Sir Tom was appointed chief executive of AstraZeneca PLC after the merger of Astra AB and Zeneca Group PLC in 1999. He was a non-executive director of Lloyds TSB Group PLC until 2004 and is chairman of the British Pharma Group.

Member of the chairman's and remuneration committees

16 Dr W E Massey
Walter Massey (66) joined BP's board in 1998, having previously been a director of Amoco. He is president of Morehouse College, a non-executive director of Motorola, Bank of America and McDonald's Corporation and a member of President Bush's Council of Advisors on Science and Technology.

Member of the chairman's and nomination committees and chairman of the ethics and environment assurance committee

17 H M P Miles, OBE
Michael Miles (68) joined BP's board in 1994. In 1988, he became an executive director of John Swire & Sons Ltd. He was chairman of Swire Pacific between 1984 and 1988. He is chairman of Schroders plc, non-executive chairman of Johnson Matthey Plc and a director of BP Pension Trustees Ltd.

Member of the chairman's, audit and ethics and environment assurance committees

18 Sir Robin Nicholson, FREng, FRS
Sir Robin (70) joined BP's board in 1987. He represents the board on the BP technology advisory council. In 1976, he became managing director of Inco Europe Limited. He was chief scientific adviser in the Cabinet Office from 1981 to 1985. Between 1986 and 1996, he was an executive director of Pilkington. He is a non-executive director of Rolls-Royce Group plc.

Member of the chairman's and nomination committees and chairman of the remuneration committee

19 M H Wilson
Michael Wilson (67) joined BP's board in 1998, having previously been a director of Amoco. He was a member of the Canadian Parliament from 1979 to 1983 and held various ministerial posts, including Finance, Industry, Science, Technology, and International Trade. He is chairman of UBS Canada and a non-executive director of Manufacturers Life Insurance Company. He is an Officer of the Order of Canada.

Member of the chairman's, audit and ethics and environment assurance committees

Changes to the board
Floris Maljers retired on 15 April 2004. On 1 July 2004, Dick Olver retired, Iain Conn was appointed an executive director and Sir Tom McKillop was appointed a non-executive director. Douglas Flint was appointed a non-executive director on 1 January 2005.

Company secretary
David Jackson (52) was appointed company secretary in 2003. A solicitor, he is a member of the Listing Authorities Advisory Committee and a director of Business in the Community.

Shareholdings and Annual General Meeting

Register of members holding BP ordinary shares as at 31 December 2004

Range of holdings	Number of shareholders	Percentage of total shareholders	Percentage of total share capital
1 – 200	59,200	17.13	0.01
201 – 1,000	132,091	38.22	0.31
1,001 – 10,000	138,359	40.04	1.96
10,001 – 100,000	13,764	3.98	1.31
100,001 – 1,000,000	1,300	0.38	2.15
Over 1,000,000[a]	867	0.25	94.26
	345,581	100.00	100.00

[a]Includes JPMorgan Chase Bank, holding 32.50% of the total share capital as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares as at 31 December 2004[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1 – 200	38,971	23.85	0.04
201 – 1,000	38,789	23.74	0.30
1,001 – 10,000	65,628	40.16	3.35
10,001 – 100,000	19,249	11.78	7.21
100,001 – 1,000,000	746	0.46	1.92
Over 1,000,000[b]	14	0.01	87.18
	163,397	100.00	100.00

[a]One ADS represents six ordinary shares.
[b]One of the holders of ADSs represents some 824,700 underlying holders.

At 31 December 2004, there were also 1,664 preference shareholders.

Substantial shareholdings

At the date of this report, the company has been notified that JPMorgan Chase Bank, as depositary for American depositary shares (ADSs), holds interests through its nominee, Guaranty Nominees Limited, in 6,995,048,776 ordinary shares (32.50% of the company's ordinary share capital). Included in this total is part of the holding of the Kuwait Investment Office (KIO). Either directly or through nominees, the KIO holds interests in 715,040,000 ordinary shares (3.32% of the company's ordinary share capital). Barclays plc holds interests in 747,585,529 ordinary shares (3.47% of the company's ordinary share capital) and Legal and General Investment Management holds interests in 768,172,570 ordinary shares (3.57% of the company's share capital).

At the date of this report, the company has been notified of the following interests in preference shares. Co-operative Insurance Society Limited holds interests in 1,550,538 8% 1st preference shares (21.44% of that class) and 1,789,796 9% 2nd preference shares (32.70% of that class). The National Farmers Union Mutual Insurance Society Ltd holds 945,000 8% 1st preference shares (13.07% of that class) and 987,000 9% 2nd preference shares (18.03% of that class). Prudential plc holds interests in 528,150 8% 1st preference shares (7.30% of that class) and 644,450 9% 2nd preference shares (11.77% of that class). Royal & SunAlliance Insurance plc holds interests in 287,500 8% 1st preference shares (3.97% of that class) and 250,000 9% 2nd preference shares (4.57% of that class). Ruffer Limited Liability Partnership holds interests in 750,000 9% 2nd preference shares (13.70% of that class).

It should be noted that the total preference shares in issue comprise only 0.39% of the company's total issued nominal share capital, the rest being ordinary shares.

Annual General Meeting

The 2005 annual general meeting will be held on Thursday 14 April 2005 at 11.00 a.m. at the Royal Festival Hall, Belvedere Road, London SE1 8XX, UK. A separate notice convening the meeting is sent to shareholders with this Report, together with an explanation of the items of special business to be considered at the meeting.

All resolutions of which notice has been given will be decided on a poll.

Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the notice of the annual general meeting.

By order of the board
David J Jackson
Secretary
7 February 2005

EXHIBIT I
Applicant's Chief Officers
(resumes attached)

President	D.C. Byers
VP & Chief Financial Officer	S.J. Riney
VP & Chief Tax Officer	P.D. Wessells
Vice President	O.A. Alvarez
Vice President	J.A. Taylor
Vice President	Andy Netemeyer
Vice President	W.T. Benham
Treasurer	R.J. Novaria
Secretary	D.A. Plumb

Custodian of Applicant's Accounting Records

Mike Deyo
501 Westlake Park Boulevard
Houston, TX 77079

Phone: 281-366-4607
Fax: 281-366-0203

CAMERON BYERS: **President**
BP Energy Company, Houston, TX

Responsibilities: Oversees the North American Gas and Power merchant energy business, which is a leading provider of natural gas, power and risk management services to the industrial and utility sectors in the US and Canada

Prior Experience:

Chief Operating Officer, North America Gas and Power
BP Amoco, Houston, TX

- Financial and operational performance of North American gas and power trading and marketing

General Manager, Commercial Refining and Trading
BP Amoco Europe

- Develop and deliver business strategies
- Acquisition and trading of crude oil for refinery use

Production Planning Manager
BP Oil Grangemouth Refinery Ltd.

- Plan and direct business performance
- Develop commercial awareness of the refinery
- Develop synergy links with supply chain and marketing businesses
- Chairman of Crude Oil and Gas Operations Networks in Scotland

Commercial Manager, BP Oil Alliance Refinery
Louisiana

- Business development, financial services, and materials management
- Redesign business plan and restructure commercial department
- US representative for company's global commercial refining network

Regional Sales Manager
BP Marine International
London, England

- Develop and deliver marine fuels sales targets to 15 major shipping accounts in the U.K. and Eastern Europe.

Commercial Analyst/Product Trader
BP France
Paris, France

- Review of supply economics and prevailing trading patterns for BP France's bulk product sales.

Supply Analyst/Business Analyst
BP Oil Trade and Supply
London and Copenhagen

- Commercial appraisal and development of business opportunities in Northwest Europe. Negotiation and implementation of term product contracts and operations in Middle East.

Education: **Edinburgh University** – Bachelor Comm. (Economics/Marketing/International Business)

STEPHEN J. RINEY	Vice President & Chief Financial Officer BP Energy Company, Houston, TX
Responsibilities:	Responsible for corporation financial control and compliance functions
Prior Experience:	Held broad range of petroleum sector positions including gasoline marketing, lubricants, petrochemicals, exploration and production, and corporate headquarters staff Prior to 1991, Manager, International Tax Practice at KPMG
Education:	B. A. University of Notre Dame, 1982 MBA University of Chicago, 1991

PAUL D. WESSELLS	Vice President & General Tax Officer BP Energy Company, Houston, TX
Responsibilities:	Assure that the corporation complies with all relevant tax laws
Prior Experience:	Internal Revenue Service, 1973-74; Estate Tax Attorney, Austin, Texas Gulf Oil Corporation, 1974-82; various positions in the Tax Department located in Houston, Texas, Denver, Colorado and Pittsburgh, Pennsylvania BP America Inc., 1982-present; various positions in the Tax Function located in Cleveland, Ohio, London, England, Anchorage, Alaska, Houston, Texas and Warrenville, Illinois
Affiliations:	Member, State Bar of Texas Member, American Bar Association
Education:	B.A. Southern Methodist University, 1968 J.D. University of Texas, 1972

ROBERT J. NOVARIA	Treasurer BP Energy Company, Houston, TX
Responsibilities:	Responsible for cash management, banking and disbursement functions
Prior Experience:	Director of Credit for Amoco Corporation. During his 27 year career, has held various other leadership positions in the financial area for Amoco and BP (Atlanta, GA, Chicago, IL and Warrenville, IL)
Affiliations:	Member of Association of Financial Professionals
Education:	Bachelor of Science in General Engineering and a Master of Business Administration, both from the University of Illinois

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DEBRA A. PLUMB	Secretary BP Energy Company, Houston, TX
Responsibilities:	Responsible for the US Corporate Secretary function for several hundred business entities
Prior Experience:	Supervisor, Legal Support Services for Amoco Corporation (Chicago IL)
Affiliations:	Member of the American Society of Corporate Secretaries
Education:	Bachelor of Arts in Liberal Arts and Studies from DePaul University, Chicago, IL

ORLANDO A. ALVAREZ **Vice President, East Region**
BP Energy Company, Houston, TX

Responsibilities:

Direct the company's energy trading operations in the Gulf Coast and Eastern areas of North America

- Gas and power marketing
- Risk management, asset management, supply optimization
- Long and short term contracts in the wholesale and retail (commercial and industrial) markets in the eastern United States
- Key member of the leadership team that has built BP's North American gas and power merchant business into one of North America's leading players, providing natural gas, power and risk management services to the industrial and utility sectors across the continent

Prior Experience:

Positions held since 1988 include:

- Natural Gas Trader
- Supply and Transportation Manager
- Manager of group responsible for gas processing activity for a number of plants along the Gulf of Mexico
- Financial/Accounting activities for a major interstate pipeline
- Financial/Accounting activities for a supply performance group responsible for monitoring pipeline take-or-pay omnibus agreements with producers

Education:

Bachelor of Business Administration in Accounting from Lamar University, Texas

JAMES A. TAYLOR: **Vice President, Western Region**
BP Energy Company, Houston, TX

Responsibilities: Management of trading and marketing of natural gas and electricity in the Western U.S.

- Gas and power marketing;
- Risk management, asset management, supply optimization;
- Long and short term contracts in the wholesale and retail (commercial and industrial) markets in the western United States.

Prior Experience: **Director, Houston Ship Channel Trading Team**

Director, East Trading Team

Director, Strategic Planning

Area Manager, Gas Supply

Representative, Transportation and Exchange
BP Amoco, Houston, TX

Education: **Texas Tech University –** Bachelor of Business Administration

ANDREW NETEMEYER: **Vice President, Power Trading**
BP Energy Company, Houston, TX

Responsibilities: Management of wholesale power trading operations in North America:

- Strategy and systems development;
- Evaluation and approval of long term generation positions;
- Management of power portfolio risk program;
- Development and direction of power trading capability for monetization of power positions at cogeneration locations;
- Management of retail efforts and trading desks for various third parties.

Prior Experience: **Vice President, Energy Management Services**
BP Amoco, Houston, TX

- Directed the North American Energy Management Marketing strategy;
- Initiated and developed numerous large cogeneration projects;
- Developed web-based EMS system for utility billing and accounting.

Managing Director, Wholesale Marketing
Illinova Energy Partners, Midvale, UT

- Directed wholesale power marketing, trading, and operations for Western U.S.;
- Developed internal scheduling capabilities for energy deliveries nationwide;
- Developed energy portfolio and risk management consulting capabilities;
- Established Illinova Energy Partners as one of the top ten power marketers in the nation.

Director of Marketing
Illinova Power Marketing

- Created and implemented national marketing strategy for entrance into unregulated wholesale energy business;
- Developed wholesale marketing, sales, and organizational plan;
- Directed initial penetration of the western wholesale energy market;
- Assisted with development of initial marketing and operations systems, including account management, risk management, scheduling, and market analysis systems.

Market Development Director
Illinois Power Company

- Energy management, economic development, energy sales, new technology programs

Education: **Illinois State University -** Master of Business Administration

University of Illinois - Bachelor of Science, Electrical Engineering

W. T. (Bill) BENHAM: **Vice President, Regulatory Affairs**
BP Energy Company, Houston, TX

Responsibilities:

Representation at state and federal governmental agencies in the United States and Mexico in the areas of natural gas and power, including imports and exports of natural gas and LNG; regulatory expertise for international projects.

Prior Experience:

Senior Attorney
Amoco Production Company, Houston, TX

Attorney
Texaco, Inc.

Attorney
Federal Power Commission

Affiliations:

District of Columbia Bar Association - Member

Producer Joint Advisory Committee – Past Chair

Natural Gas Supply Association - Member

Legal Committee and Federal Regulatory Affairs Committee – Past Chair

Coalition for Gas Based Environmental Solutions – Co-Chair

Editorial Board of "Natural Gas" magazine - Member

Gas Industry Standards Board – Board Member

Education:

Tulane University School of Law – Doctor of Jurisprudence

College of William and Mary – Bachelor of Arts

EXHIBIT J

Evidence of Applicant's Technical Fitness

BP Energy Company employs a staff of more than 17 people with varying levels of responsibility for operations in the State of Pennsylvania.

Orlando Alvarez is Vice President of Applicant with responsibility for the Eastern Region and has more than 10 years of experience marketing gas in this region. His direct reports include:

Mark Hanson - Manager, Mid Atlantic Marketing and Origination

- 15+ years of experience in the gas marketing industry
- 23 years with BP and its predecessors
- Manages a staff of 8 marketers in the Mid-Atlantic Region

Tom Lockett - Manager, Northeast Marketing and Origination

- Extensive experience in the gas marketing business
- 8 years with BP and its predecessors
- Manages a staff of 3 marketers in the Northeast, including eastern Pennsylvania

Don McLemore - Manager of Supply and Transportation

- 15+ years in the gas marketing industry
- 23 years with BP and its predecessors
- Oversees 4 managers, one of which manages operations in the Mid-Atlantic Region

Phyllis Taylor – Optimizer

- Reports to Don McLemore
- Manages a staff of 3 who are responsible for nominating gas flows on pipelines in the Mid-Atlantic Region

Throughout Applicant, every employee, along with his/her team leader or manager, creates a Personal Development Plan each year that includes development actions such as attending courses (both internal & external), as well as on the job training. Every employee is strongly encouraged to attend five (5) training days per year. Technical courses sponsored by external providers are provided as needed and internal courses on a variety of topics are offered periodically. Methods are in place to measure progress in the development of our employees.

Applicant continues to grow and hire additional people based on business needs. Systems are in place to measure employee satisfaction and their pay compared to the market to ensure it is attracting and retaining critical skills.

Applicant plans to further develop its business activities in the Mid Atlantic Region by building on its success serving and supplying gas consumers off the Columbia Gas Transmission and Dominion Transportation systems. Applicant plans to expand its services on both of these pipelines as well as behind the city-gates through sales to industrial and commercial customers tied to local distribution companies in the Mid Atlantic Region, including Pennsylvania.

AFFIDAVIT

State of Texas :
: ss.
County of Harris :

ORLANDO A. ALVAREZ, Affiant, being duly sworn according to law, deposes and says that:

He is a Vice President of BP Energy Company, the Applicant;

He is authorized to and does make this affidavit for said Applicant;

That BP Energy Company, the Applicant herein, acknowledges that BP Energy Company may have obligations pursuant to this Application consistent with the Public Utility Code of the Commonwealth of Pennsylvania, Title 66 of the Pennsylvania Consolidated Statutes; or with other applicable statutes or regulations including Emergency Orders which may be issued verbally or in writing during any emergency situations that may unexpectedly develop from time to time in the course of doing business in Pennsylvania.

That BP Energy Company, the Applicant herein, asserts that it possesses the requisite technical, managerial, and financial fitness to render natural gas supply service within the Commonwealth of Pennsylvania and that the Applicant will abide by all applicable federal and state laws and regulations and by the decisions of the Pennsylvania Public Utility Commission.

That BP Energy Company, the Applicant herein, certifies to the Commission that it is subject to, will pay, and in the past has paid, the full amount of taxes imposed by Articles II and XI of the Act of March 4, 1971 (P.L. 6, No. 2), known as the Tax Reform Act of 1971 and any tax imposed by Chapter 22 of Title 66. The Applicant acknowledges that failure to pay such taxes or otherwise comply with the taxation requirements of, shall be cause for the Commission to revoke the license of the Applicant. The Applicant acknowledges that it shall report to the Commission its jurisdictional natural gas sales for ultimate consumption, for the previous year or as otherwise required by the Commission. The Applicant also acknowledges that it is subject to 66 Pa. C.S. §506 (relating to the inspection of facilities and records).

Applicant, by filing of this application waives confidentiality with respect to its state tax information in the possession of the Department of Revenue, regardless of the source of the information, and shall consent to the Department of Revenue providing that information to the Pennsylvania Public Utility Commission.

That BP Energy Company, the Applicant herein, acknowledges that it has a statutory obligation to conform with 66 Pa. C.S. §506, and the standards and billing practices of 52 PA. Code Chapter 56.

That the Applicant agrees to provide all consumer education materials and information in a timely manner as requested by the Commission's Office of Communications or other Commission bureaus. Materials and information requested may be analyzed by the Commission to meet obligations under applicable sections of the law.

That the facts above set forth are true and correct/true and correct to the best of his/her knowledge, information, and belief.

O. Alvarez

Signature of Affiant

Sworn and subscribed before me this 15th day of August, 2005.

NOEY S. YOUNG
Notary Public, State of Texas
My Commission Expires
April 24, 2007

Noey S. Young

Signature of official administering oath

My commission expires 4-24-07.

AFFIDAVIT

State of Texas :
: ss.
County of Harris :

ORLANDO A. ALVAREZ, Affiant, being duly sworn according to law, deposes and says that:

He is a Vice President of BP Energy Company, the Applicant herein;

That he is authorized to and does make this affidavit for said Applicant;

That BP Energy Company, the Applicant herein, has the burden of producing information and supporting documentation demonstrating its technical and financial fitness to be licensed as a natural gas supplier pursuant to 66 Pa. C.S. §2208(c)(1).

That BP Energy Company, the Applicant herein, has answered the questions on the application correctly, truthfully, and completely and provided supporting documentation as required.

That BP Energy Company, the Applicant herein, acknowledges that it is under a duty to update information provided in answer to questions on this application and contained in supporting documents.

That BP Energy Company, the Applicant herein, acknowledges that it is under a duty to supplement information provided in answer to questions on this application and contained in supporting documents as requested by the Commission.

That the facts above set forth are true and correct to the best of his/her knowledge, information, and belief, and that he/she expects said Applicant to be able to prove the same at hearing.

O. Alvarez
Signature of Affiant

Sworn and subscribed before me this 15th day of August, 2005.

mdV

NOEY S. YOUNG
Notary Public, State of Texas
My Commission Expires
April 24, 2007

Noey S. Young
Signature of official administering oath

My commission expires 4-24-07.

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the foregoing document upon the participants listed below in accordance with the requirements of Section 1.54 (relating to service by a participant).

VIA FIRST-CLASS MAIL

Irwin A. Popowsky, Esq.
Office of Consumer Advocate
Forum Place, 5th Floor
555 Walnut Street
Harrisburg, PA 17101-1923

William R. Lloyd, Jr., Esq.
Office of Small Business Advocate
Commerce Building, Suite 1102
300 North Second Street
Harrisburg, PA 17101

Office of the Attorney General
Bureau of Consumer Protection
Strawberry Square, 14th Floor
Harrisburg, PA 17120

Commonwealth of Pennsylvania
Department of Revenue
Bureau of Compliance
Harrisburg, PA 17128-0946

Mr. Mike Vogel
NUI Valley Cities Gas
P. O. Box 3175
Union, NJ 07083-1975

Mr. Jim Evans
Mr. Tom Olsen
Penn Fuel
2 North 9th Street
GENA94
Allentown, PA 18101

Mr. Robert M. Hovanec
T. W. Phillips Gas and Oil Company
205 North Main Street
Butler, PA 16001

Mr. Richard N. Marshall
Ms. Wendy K. Saxe
PG Energy
One PEI Center
Wilkes-Barre, PA 18711-0601

Mr. Donald A. Melzer
Carnegie Natural Gas Company
800 Regis Avenue
Pittsburgh, PA 19236

Mr. Eric Burgis
Philadelphia Gas Works
800 West Montgomery Avenue
Philadelphia, PA 19122

Mr. Paul R. Mundy
National Fuel Gas Distribution Corp.
10 Lafayette Square
Buffalo, NY 14203

Mr. Joe Gregorini
Mr. Bill McKeown
The Peoples Natural Gas Company
625 Liberty Avenue
Pittsburgh, PA 15222

Mr. David Beaston
Mr. Bob Krieger
UGI
225 Morgantown Road
P. O. Box 12677
Reading, PA 15222

Ms. Antionette Litchy
Equitable Gas Company
200 Allegheny Center Mall
Pittsburgh, PA 15212-5352

Certificate of Service
Page 2

Mr. Erich Evans
Ms. Heather Bauer
Columbia Gas of PA, Inc.
200 Civic Center Drive
Columbus, OH 43215

Mr. Kevin Carrabine
PECO
300 Front Street Building 2
Conshohocken, PA 19428

Susan E. Bruce

Dated this 17th day of August, 2005, in Harrisburg, Pennsylvania.

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P. O. BOX 3265, HARRISBURG PA 17105-3265

IN REPLY PLEASE
REFER TO OUR FILE
Secretary
717-772-7777

August 25, 2005

A-125142

SUSAN E BRUCE ESQUIRE
MCNEES WALLACE & NURICK LLC
P O BOX 1166
100 PINE STREET
HARRISBURG PA 17108-1166

DOCUMENT
FOLDER

Dear Ms. Bruce:

The Application of BP Energy Company, filed in this Office on August 17, 2005, for approval to supply Natural Gas Services as a Supplier of Natural Gas, and as a Broker, Marketer and Aggregator engaged in the business of supplying natural gas services, is hereby acknowledged.

Pursuant to the Commission's Final Order, entered July 16, 1999, at M-00991249F0002, all entities wishing to engage in the business of a natural gas supplier must hold a license issued by the Commission, in order to provide services.

The application of BP Energy Company will receive the attention of the Commission, and you will be advised of any further necessary procedure.

Please reference docket number A-125142 for all future filings pertaining to this application.

DOCKETED
AUG 25 2005

Sincerely,

James J. McNulty

James J. McNulty
Secretary

JJM:ddt

Cc: Michelle Voinorosky, Esquire
Justin Stuhldreher, Esquire

COMMONWEALTH OF PENNSYLVANIA

DATE: August 25, 2005

SUBJECT: A-125142

TO: Bureau of Fixed Utility Services

FROM: James J. McNulty, Secretary ddt

DOCUMENT FOLDER

Attached is a copy of the Application of BP Energy Company for a license to supply Natural Gas Services as a Supplier of Natural Gas, and as a Broker, Marketer and Aggregator engaged in the business of supplying natural gas services to the public in the Commonwealth of Pennsylvania.

This matter is assigned to your Bureau for appropriate action.

Attachment

cc: Law

ddt

PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIPT

The addressee named here has paid the PA P.U.C. for the following bill:

DATE: 8/26/2005
RECEIPT NO: 203544

SUSAN E. BRUCKE
MCNEES WALLACE & NURICK LLC
P.O. BOX 1166
HARRISBURG PA 17108-1166

DOCUMENT
FOLDER

IN RE: Application fees for BP ENERGY COMPANY

Docket Number A-125142.................................... $350.00

REVENUE ACCOUNT: 001780-017601-102

CHECK NUMBER: 141532
CHECK AMOUNT: $350.00

Stephen Reed
(for Department of Revenue)

DOCKETED
AUG 2 9 2005