DOCKET NO.: A-125068
RESPONDENT OR APPLICANT: RILEY NATURAL GAS COMPANY
PARTY OR COMPLAINANT:

ENTRY	TYPE	DATE	BUREAU	PERSONNEL
1	N	12/13/99	SEC	FAHNESTOCK
APP OF RILEY NATURAL GAS COMPANY AS BRK,MKT & AGGREGATOR NATURAL GAS				
2	N	12/14/99	SEC	FAHNESTOCK
SEC MEMO TO FUS ASSIGNING APPLICATION				
3	N	12/14/99	SEC	FAHNESTOCK
SEC LTR TO APPLICANT ACKNOWLEDGING RECEIPT OF APPLICATION				
4	N	12/15/99	SEC	FRISCIA
RECEIPT OF $350.00 FILING FEE ISSUED				
5	N	06/23/00	SEC	MOTTER
PROOF OF PUBLICATION (3) & PROOF OF SERVICE OF APPLICATN ETC FLD BY APPLICANT				
6	N	06/23/00	SEC	MOTTER
APPLICANT LTR ADV OF CHANGE IN PRIMARY CONTACT PERSON				
7	N	06/29/00	SEC	ZEIDERS
PROOF OF PUBLICATION OF APPLICATION FILED (1)				
8	N	07/24/00	SEC	ADAMS
RILEY NATURAL GAS FLD LTR FROM COLUMBIA GAS & PEOPLES NAT GAS RE:BONDING REQMT				
9	N	08/09/00	SEC	MOTTER
APP FLD LTR FROM PEOPLES NATURL GAS STATING APP DOES MEET BONDING REQUIREMENTS				
10	N	08/18/00	SEC	HANCOCK
ORDER SERVED TO PARTIES				
11	N	08/18/00	SEC	HANCOCK
LICENSE FOR NATURAL GAS SUPPLIER DATED 8/17/00 ISSUED				
12	N	08/17/00	SEC	GORSKI
RECOM ADOPTED - LICENSE APPLICATION APPROVED				

CAPTION SHEET CASE MANAGEMENT SYSTEM

1. REPORT DATE: 00/00 :
2. BUREAU: FUS :
3. SECTION(S): : 4. PUBLIC MEETING DATE:
5. APPROVED BY: : 00/00/00
DIRECTOR: :
SUPERVISOR: :
6. PERSON IN CHARGE: : 7. DATE FILED: 12/13/99
8. DOCKET NO: A-125068 : 9. EFFECTIVE DATE: 00/00/00

PARTY/COMPLAINANT:

RESPONDENT/APPLICANT: RILEY NATURAL GAS COMPANY

COMP/APP COUNTY: UTILITY CODE: 125068

ALLEGATION OR SUBJECT

APPLICATION OF RILEY NATURAL GAS COMPANY FOR APPROVAL TO OFFER, RENDER, FURNISH OR SUPPLY NATURAL GAS SERVICES AS A BROKER/MARKETER AND AGGREGATOR TO THE PUBLIC IN THE COMMONWEALTH OF PENNSYLVANIA, SPECIFICALLY IN THE SERVICE TERRITORIES OF NUI VALLEY CITIES GAS (NUI TRANSPORTATION SERVICES); NATIONAL FUEL GAS DISTRIBUTION CORP.; PENN FUEL (NORTH PENN GAS COMPANY & PENN FUEL GAS); THE PEOPLES NATURAL GAS COMPANY; T.W. PHILLIPS GAS AND OIL COMPANY; UGI; PG ENERGY; EQUITABLE GAS COMPANY; CARNEGIE NATURAL GAS COMPANY; COLUMBIA GAS OF PA, INC.; AND PECO.

DOCUMENT FOLDER

DOCKETED

DEC 14 1999

EEF

RIILEY NATURAL GAS COMPANY

P.O. BOX 450, BRIDGEPORT, WEST VIRGINIA 26330
(304) 842-8930
FAX: (304) 842-8936

ORIGINAL

December 7, 1999

A-125068

Mr. James J. McNulty, Secretary
B-20, North Office Building
Harrisburg, PA 17120

RE: Application for Natural Gas Supplier License

Dear Mr. McNulty:

Please find enclosed the required original and eight copies of Riley Natural Gas Company's Natural Gas Supplier License Application Package. We have also included a 3.5" floppy containing the electronic application and a standard contract.

Should you require any further information, please do not hesitate to call me at (304) 842-8930.

Yours truly,

Brian Wiseman

Brian Wiseman
Transportation & Production Coordinator

Enclosures

99 DEC 13 PM 12:08
RECEIVED
SECRETARY'S BUREAU

54

DOCUMENT FOLDER

P.O. BOX 1540
SEVERNA PARK, MARYLAND 21146
(410) 544-3328
FAX: (410) 544-3990

935 QUEEN STREET
OLEAN, NEW YORK 14760
(716) 373-0311
FAX: (716) 373-4509

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Riley Natural Gas Company for approval to offer, render, furnish, or as a(n) [as specified in item #8 below] to the public in the Commonwealth of Pennsylvania.

A-125068

To the Pennsylvania Public Utility Commission:

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

ORIGINAL

Riley Natural Gas Company
103 East Main Street
Bridgeport, WV 26330
(304) 842-8930 phone
(304) 842-8936 fax

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.

N/A

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:

Donna R. Riley, Vice President
Riley Natural Gas Company
103 East Main Street
Bridgeport, WV 26330
(304) 842-8930 phone
(304) 842-8936 fax

DOCUMENT FOLDER

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:

Donna R. Riley, Vice President
Riley Natural Gas Company
103 East Main Street
Bridgeport, WV 26330
(304) 842-8930 phone
(304) 842-8936 fax

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

DOCKETED

DEC 14 1999

N/A

RECEIVED

DEC 13 1999

PA PUBLIC UTILITY COMMISSION
SECRETARY'S BUREAU

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:

N/A

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 i[illegible]e Applicant's domestic partnership is not d[illegible]ciled 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. Additionally, provide a copy of the Applicant's Articles of Incorporation.

Give name and address of officers.

Thomas E. Riley, President	103 East Main Street
Donna R. Riley, Vice President	Bridgeport, WV 26330

The Applicant is incorporated in the state of West Virginia.

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

☐ *Affiliate(s) of the Applicant doing business in Pennsylvania are:*
N/A

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

☐ Does the Applicant have any affiliation with or ownership interest in:

NO (a) any other Pennsylvania retail natural gas supplier licensee or licensee applicant,
NO (b) any other Pennsylvania retail licensed electric generation supplier or license applicant,
YES (c) any Pennsylvania natural gas producer and/or marketer,
NO (d) any natural gas wells or
NO (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.

☐ 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.

(a) Affiliate of Petroleum Development Corporation, a Nevada Corporation, corporate headquarters located in Bridgeport, WV.

- [ ] 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.

  N/A

- [ ] 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.

  N/A

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
  - [x] a natural gas producer
  - [x] Other. (Identify the nature of service being rendered.) Aggregator/Marketer

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.
- [x] Broker/Marketer engaged in the business of supplying natural gas services.
- [x] 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.

Resale aggregated supplies to utilities, industrials and other marketing companies

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

Mid-Atlantic Region

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

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

13. **START DATE:** The Applicant proposes to begin delivering services on ________________ (approximate date).

We have been selling natural gas for several years.

14. **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
Bernard A. Ryan, 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.** James E. Patterson 10 Lafayette Square Buffalo, NY 14203 PH: 716.857.7130 FAX: 716.857-7823
Penn Fuel [North Penn Gas Company & Penn Fuel Gas] Jim Evans <u>or</u> 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 <u>or</u> teolson@papl.com	**The Peoples Natural Gas Company** Joe Gregorini <u>or</u> Bill McKeown 625 Liberty Avenue Pittsburgh, PA 15222 e-mail: jgregorini@png.cng.com PH: 412.497.6851 <u>or</u> 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 <u>or</u> Bob Krieger PO Box 12677 <u>or</u> 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 <u>or</u> Wendy K. Saxe One PEI Center Wilkes-Barre, PA 18711-0601 e-mail: marshall@pgenergy.com <u>or</u> 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.** Paula Frauen <u>or</u> Shirley Bardes-Hasson 650 Washington Road Pittsburgh, PA 15228 e-mail: pfrauen@columbiaenergygroup.com PH: 412.572.7131 FAX: 412.572.7161
	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.

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

16. **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.

N/A

17. **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.

Addressed in contract

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

N/A

18. **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.

B. Applicant must provide the following information:

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

Thomas E. Riley, President and Donna R. Riley, Vice President

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

  Darwin Stump, Controller
  Petroleum Development Corporation
  P.O. Box 26
  Bridgeport, WV 26330
  (304) 842-3597
  (304) 842-8936

19. **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.

  Thomas E. Riley, President and Donna R. Riley, Vice President

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

  N/A

- Proposed staffing and employee training commitments.

- Business plans.

- Documentation of membership in or other shall be submitted if applicable to the scope and nature of the applicant's proposed services.

20. **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.

    N/A

21. **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.

22. **<u>REPORTING REQUIREMENTS</u>**: 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.**

23. **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.

24. **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.

25. **FEE:** The Applicant has enclosed the required initial licensing fee of $350.

Applicant: Riley Natural Gas Company

By: Donna R. Riley

Title: Vice President

AFFIDAVIT

[Commonwealth/State] of West Virginia

: ss.

County of Harrison :

Thomas E. Riley, Affiant, being duly [sworn/affirmed] according to law, deposes and says that:

[He/she is the President (Office of Affiant) of Riley Natural Gas Company (Name of Applicant);]

[That he/she is authorized to and does make this affidavit for said Applicant;]

That Riley Natural Gas Company, the Applicant herein, acknowledges that [Applicant] 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 Riley Natural Gas Company, the Applicant herein, asserts that [he/she/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 Riley Natural Gas 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 Riley Natural Gas 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.

Thomas E Riley
Signature of Affiant

Sworn and subscribed before me this 7th day of December, 1999.

Tina R. Smith
Signature of official administering oath

My commission expires December 6, 2005.

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
TINA R. SMITH
ROUTE 3, BOX 87
WESTON, WV 26452
My Commission Expires December 6, 2005

AFFIDAVIT

[Commonwealth/State] of ______________________ :

: ss.

County of ____________________ :

____________________, Affiant, being duly [sworn/affirmed] according to law, deposes and says that:

[He/she is the ________________ (Office of Affiant) of ______________ (Name of Applicant);]

[That he/she is authorized to and does make this affidavit for said Applicant;]

That ________________, the Applicant herein certifies that it has caused the notice of the filing of its license appli published in the following newspapers on ______________:
(date)

A copy of the notice as it appeared in each of the above newspapers is attached. Noted on each copy is the newspaper section (name, number or letter), if applicable, and the page number on which the notice appeared.

That ________________, the Applicant will submit to the Commission the proof of publication from each newspaper in which notice of the application filing was published as soon as it is available.

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.

____
Signature of Affiant

Sworn and subscribed before me this ______ day of ____________, 19____.

____
Signature of official administering oath

My commission expires ______________________.

AFFIDAVIT

[Commonwealth/State] of West Virginia :

: ss.

County of Harrison :

Thomas E. Riley, Affiant, being duly [sworn/affirmed] according to law, deposes and says that:

[He/she is the President (Office of Affiant) of Riley Natural Gas Company (Name of Applicant);]

[That he/she is authorized to and does make this affidavit for said Applicant;]

That the Applicant herein Riley Natural Gas Company 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 the Applicant herein Riley Natural Gas Company has answered the questions on the application correctly, truthfully, and completely and provided supporting documentation as required.

That the Applicant herein Riley Natural Gas Company acknowledges that it is under a duty to update information provided in answer to questions on this application and contained in supporting documents.

That the Applicant herein Riley Natural Gas Company 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.

Thomas E. Riley

Signature of Affiant

Sworn and subscribed before me this 7th day of December, 1999.

Tina R. Smith

Signature of official administering oath

My commission expires December 6, 2005.

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
TINA R. SMITH
ROUTE 3, BOX 87
WESTON, WV 26452
My Commission Expires December 6, 2005

APPENDIX A

COMMONWEALTH OF PENNSYLVANIA
PUBLIC UTILITY COMMISSION

TAX CERTIFICATION STATEMENT

A completed Tax Certification Statement must accompany all applications for new licenses, renewals or transfers. Failure to provide the requested information and/or any outstanding state income, corporation, and sales (including failure to file or register) will cause your application to be rejected. If additional space is needed, please use white 81/2" x 11" paper. Type or print all information requested.

1. CORPORATE OR APPLICANT NAME
RILEY NATURAL GAS COMPANY

2. BUSINESS PHONE NO. (304) 842-8930
CONTACT PERSON(S) FOR TAX ACCOUNTS:
TOM RILEY

3. TRADE/FICTITIOUS NAME (IF ANY)
N/A

4. LICENSED ADDRESS (STREET, RURAL ROUTE, P.O. BOX NO.) (POST OFFICE) STATE) (ZIP)
103 EasteMain Street P.O. Box 450 WV 26330

5. TYPE OF ENTITY ☐ SOLE PROPRIETOR ☐ PARTNERSHIP ☒ CORPORATION

8. LIST OWNER(S), GENERAL PARTNERS, OR CORPORATE OFFICER(S)

NAME (PRINT)	SOCIAL SECURITY NUMBER (OPTIONAL)
Thomas E. Riley, President	___-__-____
	___-__-____
	___-__-____
	___-__-____
	___-__-____

9. LIST THE FOLLOWING STATE TAX IDENTIFICATION NUMBERS. **(ALL ITEMS: A, B, AND C MUST BE COMPLETED)**.

A. SALES TAX LICENSE (8 DIGITS) APPLICATION PENDING ☐ N/A ☐
99-60733-3

B. EMPLOYER ID (EIN) (9 DIGITS: APPLICATION PENDING ☐ N/A ☐
55-0671826

C. CORPORATE BOX NUMBER (7 DIGITS) APPLICATION PENDING ☐ N/A ☐
3511 764

10. Do you have PA employes either resident or non-resident? ☐ YES ☒ NO

11. Do you own any assets or have an office in PA? ☐ YES ☒ NO

NAME AND PHONE NUMBER OF PERSON(S) RESPONSIBLE FOR FILING TAX RETURNS

PA SALES AND USE TAX	EMPLOYER TAXES	CORPORATE TAXES
Tina Smith	Theresa Baker	Janet Potter
PHONE 304-842-8930	PHONE 304-842-3597	PHONE 304-842-3597

Telephone inquiries about this form may be directed to the Pennsylvania Department of Revenue at the following numbers: (717) 772-2673, TDD# (717) 772-2252 (Hearing Impaired Only)

BASE CONTRACT FOR SHORT-TERM SALE AND PURCHASE OF NATURAL GAS

DRAFT

A-125868

This Base Contract is entered into as of the following date: ____________
The parties to the Base Contract are the following:

Company:	Riley Natural Gas Company	*and*	Company:	____________
Referenced:	"Riley"		Referenced:	____________
Duns #:	17-782-6740		Duns #:	____________
Contract #:	XX(Contract #)		Contract #	____________
Attn:	Donna R. Riley, Vice President		Attn:	____________
Phone: (304) 842-8930	Fax: (304) 842-8936		Phone: ________	Fax: ________
Federal Tax ID Number:	55-067-1826		Federal Tax ID Number:	____________

Invoices and Payments:

Company:	Riley Natural Gas Company	Company:	____________
Attn:	Tina R. Smith, Gas Accountant	Attn:	____________
Address:	103 East Main Street P.O. Box 450 Bridgeport, WV 26330-0450	Address:	____________ ____________
	Phone: (304) 842-8930 Fax: (304) 842-8936	Phone: ________	Fax: ________
Wire Transfer or ACH Nos. (if applicable)	One Valley Bank, NA (Morgantown, WV) ABA #051503268 Account #2012146	Wire Transfer or ACH Nos. (if applicable)	____________ ____________

This Base Contract incorporates by reference for all purposes the General Terms and Conditions for Short-Term Sale and Purchase of Natural Gas. The parties hereby agree to the following provisions offered in said General Terms and Conditions **(select only one from each box, but see "*Note*" relating to Section 2.24.):**

Section 1.2 *Transaction Procedure*	☐ Oral ☐ Written	**Section 6** *Taxes*	☐ Buyer Pays At and After Delivery Point ☐ Seller Pays Before and At Delivery Point
Section 2.4 *Confirm Deadline*	☐ 2 Business Days after receipt (default) ☐ 1 Business Days after receipt	**Section 7.2** *Payment Date*	Ten (10) days from the date of Seller's invoice or 25th day of Month following Month of delivery, whichever is later.
Section 2.5 *Confirming Party*	☐ Seller ☐ Buyer ☐ Riley	**Section 7.2** *Method of Payment*	☐ Wire Transfer (WT) ☐ Automated Clearinghouse (ACH) ☐ Check
Section 3.2 *Performance Obligation*	☐ Cover Standard ☐ Spot Price Standard *Note: The following Spot Price Publication applies to both of the immediately preceding Standards and must be filled in after a Standard is selected.* Section 2.24 Spot Price Publication: ____________	**Section 13.5** Choice of Law:	____________
☐ **Special Provisions:** Number of sheets attached is _____.			

IN WITNESS WHEREOF, the parties hereto have executed this Base Contract in duplicate.

Riley Natural Gas Company	____________
(Party Name)	*(Party Name)*
By ____________	By ____________
Title Donna R. Riley, Vice President	Title ____________

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GENERAL TERMS AND CONDITIONS BASE CONTRACT FOR SHORT-TERM SALE AND PURCHASE OF NATURAL GAS

DRAFT

SECTION 1. PURPOSE AND PROCEDURES

1.1. These General Terms and Conditions are intended to facilitate purchase and sale transactions of Gas on a Firm or Interruptible basis. "Buyer" refers to the party receiving Gas and "Seller" refers to the party delivering Gas.

The parties have selected either the "Oral" version or the "Written" version of transaction procedure as indicated on the Base Contract.

Oral Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Any Gas purchase and sale transaction may be effectuated in an EDI transmission or telephone conversation with the offer and acceptance constituting the agreement of the parties. The parties shall be legally bound from the time they so agree to transaction terms and may each rely thereon. Any such transaction shall be considered a "writing" and to have been "signed". Notwithstanding the foregoing sentence, the parties agree that Confirming Party shall, and the other party may, confirm a telephonic transaction by sending the other party a Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means. Confirming Party adopts its confirming letterhead, or the like, as its signature on any Transaction Confirmation as the identification and authentication of Confirming Party.

Written Transaction Procedure:

1.2. The parties will use the following Transaction Confirmation procedure. Should the parties come to an agreement regarding a Gas purchase and sale transaction for a particular Delivery Period, the Confirming Party shall, and the other party may, record that agreement on a Transaction Confirmation and communicate such Transaction Confirmation by facsimile, EDI or mutually agreeable electronic means, to the other party by the close of the Business Day following the date of agreement. The parties acknowledge that their agreement will not be binding until the exchange of non- conflicting Transaction Confirmations or the passage of the Confirm Deadline without objection from the receiving party, as provided in Section 1.3.

1.3. If a sending party's Transaction Confirmation is materially different from the receiving party's understanding of the agreement referred to in Section 1.2., such receiving party shall notify the sending party via facsimile by the Confirm Deadline, unless such receiving party has previously sent a Transaction Confirmation to the sending party. The failure of the receiving party to so notify the sending party in writing by the Confirm Deadline constitutes the receiving party's agreement to the terms of the transaction described in the sending party's Transaction Confirmation. If there are any material differences between timely sent Transaction Confirmations governing the same transaction, then neither Transaction Confirmation shall be binding until or unless such differences are resolved including the use of any evidence that clearly resolves the differences in the Transaction Confirmations. The entire agreement between the parties shall be those provisions contained in both the Base Contract and any effective Transaction Confirmation. In the event of a conflict among the terms of (i) a Transaction Confirmation, (ii) the Base Contract, and (iii) these General Terms and Conditions, the terms of the documents shall govern in the priority listed in this sentence.

SECTION 2. DEFINITIONS

2.1. "Base Contract" shall mean a contract executed by the parties that incorporates these General Terms and Conditions by reference; that specifies the agreed selections of provisions contained herein; and that sets forth other information required herein.
2.2. "British thermal unit" or "Btu" shall have the meaning ascribed to it by the Receiving Transporter.
2.3. "Business Day" shall mean any day except Saturday, Sunday or Federal Reserve Bank holidays.
2.4. "Confirm Deadline" shall mean 5:00 p.m. in the receiving party's time zone on the second Business Day following the Day a Transaction Confirmation is received, or if applicable, on the Business Day agreed to by the parties in the Base Contract; provided, if the Transaction Confirmation is time stamped after 5:00 p.m. in the receiving party's time zone, it shall be deemed received at the opening of the next Business Day.

2.5. "Confirming Party" shall mean the party designated in the Base Contract to prepare and forward Transaction Confirmations to the other party.
2.6. "Contract" shall mean the legally-binding relationship established by (i) the Base Contract and (ii) the provisions contained in any effective Transaction Confirmation.
2.7. "Contract Price" shall mean the amount expressed in U.S. Dollars per MMBtu, as evidenced by the Contract Price on the Transaction Confirmation.
2.8. "Contract Quantity" shall mean the quantity of Gas to be delivered and taken as set forth in the Transaction Confirmation.
2.9. "Cover Standard", if applicable, shall mean that if there is an unexcused failure to take or deliver any quantity of Gas pursuant to this Contract, then the non-defaulting party shall use commercially reasonable efforts to obtain Gas or alternate fuels, or sell Gas, at a price reasonable for the delivery or production area, as applicable, consistent with: the amount of notice provided by the defaulting party; the immediacy of the Buyer's Gas consumption needs or Seller's Gas sales requirements, as applicable; the quantities involved; and the anticipated length of failure by the defaulting party.
2.10. "Day" shall mean a period of 24 consecutive hours, coextensive with a "day" as defined by the Receiving Transporter in a particular transaction.
2.11. "Delivery Period" shall be the period during which deliveries are to be made as set forth in the Transaction Confirmation.
2.12. "Delivery Point(s)" shall mean such point(s) as are mutually agreed upon between Seller and Buyer as set forth in the Transaction Confirmation.
2.13. "EDI" shall mean an electronic data interchange pursuant to an agreement entered into by the parties, specifically relating to the communication of Transaction Confirmations under this Contract.
2.14. "EFP" shall mean the purchase, sale or exchange of natural Gas as the "physical" side of an exchange for physical transaction involving gas futures contracts. EFP shall incorporate the meaning and remedies of "Firm".
2.15. "Firm" shall mean that either party may interrupt its performance without liability only to the extent that such performance is prevented for reasons of Force Majeure; provided, however, that during Force Majeure interruptions, the party invoking Force Majeure may be responsible for any Imbalance Charges as set forth in Section 4.3. related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by the Transporter.
2.16. "Secondary Firm" shall mean that either party may interrupt its performance to the extent that such performance is prevented for reasons of force Majeure or curtailment of such party's interruptible transportation and/or storage, transportation between secondary firm points, interruption or recall of recallable firm transportation or, if applicable, production behind a specific meter, without liability to the other party.
2.17. "Gas" shall mean any mixture of hydrocarbons and non-combustible gases in a gaseous state consisting primarily of methane.
2.18. "Imbalance Charges" shall mean any fees, penalties, costs or charges (in cash or in kind) assessed by a Transporter for failure to satisfy the Transporter's balance and/or nomination requirements.
2.19. "Interruptible" shall mean that either party may interrupt its performance at any time for any reason, whether or not caused by an event of Force Majeure, with no liability, except such interrupting party may be responsible for any Imbalance Charges as set forth in Section 4.3. related to its interruption after the nomination is made to the Transporter and until the change in deliveries and/or receipts is confirmed by Transporter.
2.20. "MMBtu" shall mean one million British thermal units which is equivalent to one dekatherm.
2.21. "Month" shall mean the period beginning on the first Day of the calendar month and ending immediately prior to the commencement of the first Day of the next calendar month.
2.22. "Payment Date" shall mean a date, selected by the parties in the Base Contract, on or before which payment is due Seller for Gas received by Buyer in the previous Month.
2.23. "Receiving Transporter" shall mean the Transporter receiving Gas at a Delivery Point, or absent such receiving Transporter, the Transporter delivering Gas at a Delivery Point.
2.24. "Scheduled Gas" shall mean the quantity of Gas confirmed by Transporter(s) for movement, transportation or management.
2.25. "Spot Price" as referred in Section 3.2 shall mean the price listed in the publication specified by the parties in the Base Contract, under the listing applicable to the geographic location closest in proximity to the Delivery Point(s) for the relevant Day; provided, if there is no single price published for such location for such Day, but there is published a range of prices, then the Spot Price shall be the average of such high and low prices. If no price or range of prices is published for such Day, then the Spot Price shall be the average of the following: (i) the

price (determined as stated above) for the first Day for which a price or range of prices is published that next precedes the relevant Day; and (ii) the price (determined as stated above) for the first Day for which a price or range of prices is published that next follows the relevant Day.

2.26. "Transaction Confirmation" shall mean the document, substantially in the form of Exhibit A, setting forth the terms of a purchase and sale transaction formed pursuant to Section 1. for a particular Delivery Period.

2.27. "Transporter(s)" shall mean all Gas gathering or pipeline companies, or local distribution companies, acting in the capacity of a transporter, transporting Gas for Seller or Buyer upstream or downstream, respectively, of the Delivery Point pursuant to a particular Transaction Confirmation.

SECTION 3. PERFORMANCE OBLIGATION

3.1. Seller agrees to sell and deliver, and Buyer agrees to receive and purchase, the contract Quantity for a particular transaction in accordance with the terms of the Contract. Sales and purchases will be on a Firm, Secondary Firm or Interruptible basis, or such other basis as the parties may mutually agree from time to time, as specified in the Transaction Confirmation (a "Performance Obligation").

The parties have selected either the "Cover Standard" version or the "Spot Price Standard" version as indicated on the Base Contract.
Cover Standard:
3.2. In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, the exclusive and sole remedy of the parties in the event of a breach of Performance Obligation, other than the delivery and receipt of Gas on an Interruptible basis, shall be the recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard for replacement Gas or alternative fuels and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas; adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the exclusive and sole remedy of the non-breaching party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s).
Spot Price Standard:
3.2. In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, the exclusive and sole remedy of the parties in the event of a breach of a Firm obligation shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price.

3.3. EXCEPT AS OTHERWISE SPECIFICALLY PROVIDED HEREIN, IN NO EVENT WILL EITHER PARTY BE LIABLE UNDER THIS CONTRACT, WHETHER IN CONTRACT, IN TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY), OR OTHERWISE, FOR INCIDENTAL, CONSEQUENTIAL, SPECIAL, OR PUNITIVE DAMAGES.

SECTION 4. TRANSPORTATION, NOMINATIONS AND IMBALANCES

4.1. Seller shall have the sole responsibility for transporting the Gas to the Delivery Point(s) and for delivering such Gas at a pressure sufficient to effect such delivery but not to exceed the maximum operating pressure of the Receiving Transporter. Buyer shall have the sole responsibility for transporting the Gas from the Delivery Point(s).
4.2. The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.
4.3. The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's actions or inactions (which shall include, but shall not be limited to, Buyer's failure to accept quantities of Gas equal to the Scheduled Gas), then Buyer shall pay for such Imbalance Charges, or reimburse Seller for such Imbalance Charges paid by Seller to the Transporter. If the Imbalance Charges were incurred as a result of Seller's actions or inactions (which shall include, but shall not be limited to, Seller's failure to deliver quantities of Gas equal to the Scheduled Gas), then Seller shall pay for such Imbalance Charges, or reimburse Buyer for such Imbalance Charges paid by Buyer to the Transporter.

SECTION 5. QUALITY AND MEASUREMENT

All Gas delivered by Seller shall meet the quality and heat content requirements of the Receiving Transporter. The unit of quantity measurement for purposes of this Contract shall be one MMBtu dry. Measurement of Gas quantities hereunder shall be in accordance with the established procedures of the Receiving Transporter.

SECTION 6. TAXES

The parties have selected either the "Buyer Pays At and After Delivery Point" version or the "Seller Pays Before and At Delivery Point" version as indicated on the Base Contract.
Buyer Pays At and After Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas at the Delivery Point(s) and all Taxes after the Delivery Point(s). If a party is required to remit or pay Taxes that are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.
Seller Pays Before and At Delivery Point:
Seller shall pay or cause to be paid all taxes, fees, levies, penalties, licenses or charges imposed by any government authority ("Taxes") on or with respect to the Gas prior to the Delivery Point(s) and all Taxes at the Delivery Point(s). Buyer shall pay or cause to be paid all Taxes on or with respect to the Gas after the Delivery Point(s). If a party is required to remit or pay Taxes which are the other party's responsibility hereunder, the party responsible for such Taxes shall promptly reimburse the other party for such Taxes. Any party entitled to an exemption from any such Taxes or charges shall furnish the other party any necessary documentation thereof.

SECTION 7. BILLING, PAYMENT AND AUDIT

7.1. Seller shall invoice Buyer for Gas delivered and received in the preceding Month and for any other applicable charges, providing supporting documentation acceptable in industry practice to support the amount charged. If the actual quantity delivered is not known by the billing date, billing will be prepared based on the quantity of Scheduled Gas. The invoiced quantity will then be adjusted to the actual quantity on the following Month's billing

or as soon thereafter as actual delivery information is available.
7.2. Buyer shall remit the amount due in the manner specified in the Base Contract, in immediately available funds, on or before the later of the Payment Date or 10 days after receipt of the invoice by Buyer; provided that if the Payment Date is not a Business Day, payment is due on the next Business Day following that date. If Buyer fails to remit the full amount payable by it when due, interest on the unpaid portion shall accrue at a rate equal to the lower of (i) the then-effective prime rate of interest published under "Money Rates" by The Wall Street Journal, plus two percent per annum from the date due until the date of payment; or (ii) the maximum applicable lawful interest rate. If Buyer, in good faith, disputes the amount of any such statement or any part thereof, Buyer will pay to Seller such amount as it concedes to be correct; provided, however, if Buyer disputes the amount due, Buyer must provide supporting documentation acceptable in industry practice to support the amount paid or disputed.
7.3. In the event any payments are due Buyer hereunder, payment to Buyer shall be made in accordance with Section 7.2. above.
7.4. A party shall have the right, at its own expense, upon reasonable notice and at reasonable times, to examine the books and records of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment, or computation made under the Contract. This examination right shall not be available with respect to proprietary information not directly relevant to transactions under this Contract. All invoices and billings shall be conclusively presumed final and accurate unless objected to in writing, with adequate explanation and/or documentation, within two years after the Month of Gas delivery. All retroactive adjustments under Section 7. shall be paid in full by the party owing payment within 30 days of notice and substantiation of such inaccuracy.

SECTION 8. TITLE, WARRANTY AND INDEMNITY

8.1. Unless otherwise specifically agreed, title to the Gas shall pass from Seller to Buyer at the Delivery Point(s). Seller shall have responsibility for and assume any liability with respect to the Gas prior to its delivery to Buyer at the specified Delivery Point(s). Buyer shall have responsibility for and assume any liability with respect to said Gas after its delivery to Buyer at the Delivery Point(s).
8.2. Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims.
8.3. Seller agrees to indemnify Buyer and save it harmless from all losses, liabilities or claims including attorneys' fees and costs of court ("Claims"), from any and all persons, arising from or out of claims of title, personal injury or property damage from said Gas or other charges thereon which attach before title passes to Buyer. Buyer agrees to indemnify Seller and save it harmless from all Claims, from any and all persons, arising from or out of claims regarding payment, personal injury or property damage from said Gas or other charges thereon which attach after title passes to Buyer.
8.4. Notwithstanding the other provisions of this Section 8., as between Seller and Buyer, Seller will be liable for all Claims to the extent that such arise from the failure of Gas delivered by Seller to meet the quality requirements of Section 5.

SECTION 9. NOTICES

9.1. All Transaction Confirmations, invoices, payments and other communications made pursuant to the Base Contract ("Notices") shall be made to the addresses specified in writing by the respective parties from time to time.
9.2. All Notices required hereunder may be sent by facsimile or mutually acceptable electronic means, a nationally recognized overnight courier service, first class mail or hand delivered.
9.3. Notice shall be given when received on a Business Day by the addressee. In the absence of proof of the actual receipt date, the following presumptions will apply. Notices sent by facsimile shall be deemed to have been received upon the sending party's receipt of its facsimile machine's confirmation of successful transmission, if the day on which such facsimile is received is not a Business Day or is after five p.m. on a Business Day, then such facsimile shall be deemed to have been received on the next following Business Day.

Notice by overnight mail or courier shall be deemed to have been received on the next Business Day after it was sent or such earlier time as is confirmed by the receiving party. Notice via first class mail shall be considered delivered two Business Days after mailing.

SECTION 10. FINANCIAL RESPONSIBILITY

10.1. When reasonable grounds for insecurity of payment or title to the Gas arise, either party may demand adequate assurance of performance. Adequate assurance shall mean sufficient security in the form and for the term reasonably specified by the party demanding assurance, including, but not limited to, a standby irrevocable letter of credit, a prepayment, a security interest in an asset acceptable to the demanding party or a performance bond or guarantee by a creditworthy entity. In the event either party shall (i) make an assignment or any general arrangement for the benefit of creditors; (ii) default in the payment obligation to the other party; (iii) file a petition or otherwise commence, authorize, or acquiesce in the commencement of a proceeding or cause under any bankruptcy or similar law for the protection of creditors or have such petition filed or proceeding commenced against it; (iv) otherwise become bankrupt or insolvent (however evidenced); or (v) be unable to pay its debts as they fall due; then the other party shall have the right to either withhold and/or suspend deliveries or payment, or terminate the Contract without prior notice, in addition to any and all other remedies available hereunder. Seller may immediately suspend deliveries to Buyer hereunder in the event Buyer has not paid any amount due Seller hereunder on or before the second day following the date such payment is due.
10.2. Each party reserves to itself all rights, set-offs, counterclaims, and other defenses which it is or may be entitled to arising from the Contract.

SECTION 11. FORCE MAJEURE

11.1. Except with regard to a party's obligation to make payment due under Section 7. and Imbalance Charges under Section 4, neither party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by Force Majeure. The term "Force Majeure" as employed herein means any cause not reasonably within the control of the party claiming suspension, as further defined in Section 11.2.
11.2. Force Majeure shall include but not be limited to the following: (i) physical events such as acts of God, landslides; lightning, earthquakes, fires, storms or storm warnings, such as hurricanes, which result in evacuation of the affected area, floods, washouts, explosions, breakage or accident or necessity of repairs to machinery or equipment or lines of pipe; (ii) weather related events affecting an entire geographic region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption of firm transportation and/or storage by Transporters; (iv) acts of others such as strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections or wars; and (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, or regulation promulgated by a governmental authority having jurisdiction. Seller and Buyer shall make reasonable efforts to avoid the adverse impacts of a Force Majeure and to resolve the event or occurrence once it has occurred in order to resume performance.
11.3. Neither party shall be entitled to the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances: (i) the curtailment of interruptible or secondary firm transportation unless primary, in-path, firm transportation is also curtailed; (ii) the party claiming excuse failed to remedy the condition and to resume the performance of such covenants or obligations with reasonable dispatch; or (iii) economic hardship. The party claiming Force Majeure shall not be excused from its responsibility for Imbalance Charges.
11.4. Notwithstanding anything to the contrary herein, the parties agree that the settlement of strikes, lockouts or other industrial disturbances shall be entirely within the sole discretion of the party experiencing such disturbance.
11.5. The party whose performance is prevented by Force Majeure must provide notice to the other party. Initial notice may be given orally; however, written notification with reasonably full particulars of the event or occurrence is required as soon as reasonably possible. Upon providing written notification of Force Majeure to the other party, the affected party will be relieved of its obligation to make or accept delivery of Gas as applicable to the extent and for the duration of Force Majeure, and neither party shall be deemed to have failed in such obligations to the other during such occurrence or event.
11.6. Absent a specific commitment to the contrary in the applicable Transaction Confirmation, a reference to a particular Delivery Point shall not be construed as a commitment of any particular supply source to that

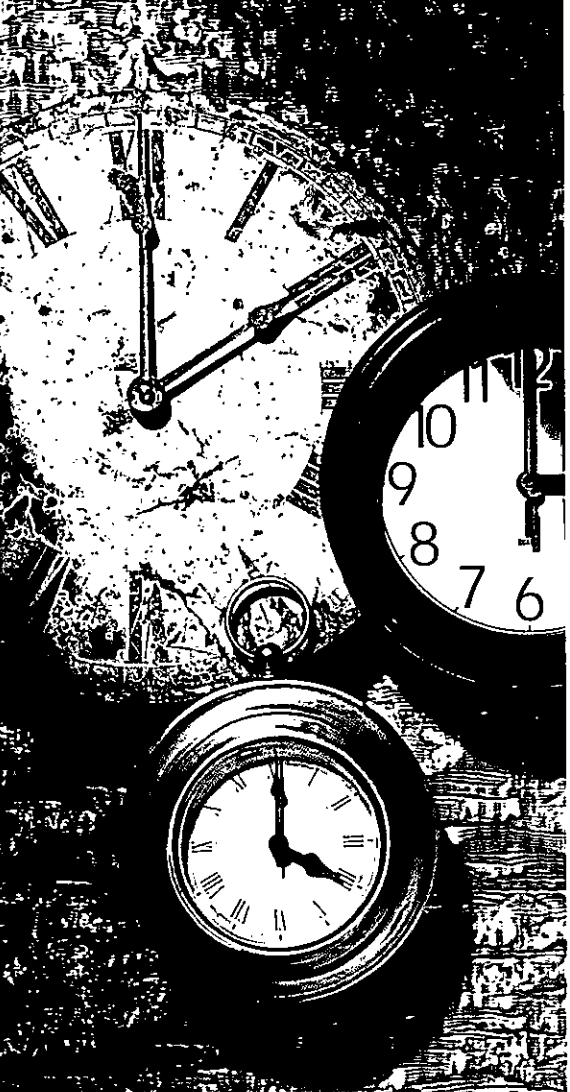
transaction. The parties understand and agree that Seller's Gas supplies are aggregated from several geographic areas and that a material disruption of supply in one such area may impair Seller's ability to make deliveries hereunder. Unless specifically provided in the applicable Transaction Confirmation, Seller shall have no obligation, during an event of Force Majeure suffered by Seller, to make deliveries using Gas in storage, Liquefied Natural Gas or any other commercially unusual measures.

SECTION 12. TERM

This Contract may be terminated on 30 days written notice, but shall remain in effect until the expiration of the latest Delivery Period of any Transaction Confirmation(s). The rights of either party pursuant to Section 7.4., the obligations to make payment hereunder, and the obligation of either party to indemnify the other, pursuant hereto shall survive the termination of the Base Contract or any Transaction Confirmation.

SECTION 13. MISCELLANEOUS

13.1. This Contract shall be binding upon and inure to the benefit of the successors, assigns, personal representatives, and heirs of the respective parties hereto, and the covenants, conditions, rights and obligations of this Contract shall run for the full term of this Contract. No assignment of this Contract, in whole or in part, will be made without the prior written consent of the non-assigning party, which consent will not be unreasonably withheld or delayed; provided, either party may transfer its interest to any parent or affiliate by assignment, merger or otherwise without the prior approval of the other party. Upon any transfer and assumption, the transferor shall not be relieved of or discharged from any obligations hereunder.
13.2. If any provision in this Contract is determined to be invalid, void or unenforceable by any court having jurisdiction, such determination shall not invalidate, void, or make unenforceable any other provision, agreement or covenant of this Contract.
13.3. No waiver of any breach of this Contract shall be held to be a waiver of any other or subsequent breach.
13.4. This Contract sets forth all understandings between the parties respecting each transaction subject hereto, and any prior contracts, understandings and representations, whether oral or written, relating to such transactions are merged into and superseded by this Contract and any effective Transaction Confirmation(s). This Contract may be amended only by a writing executed by both parties.
13.5. The interpretation and performance of this Contract shall be governed by the laws of the state specified by the parties in the Base Contract, excluding, however, any conflict of laws rule which would apply the law of another jurisdiction.
13.6. This Contract and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, State, or local governmental authority having jurisdiction over the parties, their facilities, or Gas supply, this Contract or Transaction Confirmation or any provisions thereof.
13.7. There is no third party beneficiary to this Contract.
13.8. Each party to this Contract represents and warrants that it has full and complete authority to enter into and perform this Contract. Each person who executes this Contract on behalf of either party represents and warrants that it has full and complete authority to do so and that such party will be bound thereby.



Celebrating Our 30 Year Anniversary

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Petroleum Development Corporation

1998 Annual Report

Forward-Looking Statements and Risk

Certain statements in this report, including statements of the future plans, objectives, and expected performance of the Company, are forward-looking statements that are dependent upon certain events, risks and uncertainties that may be outside the Company's control, and which could cause actual results to differ materially from those anticipated. Some of these include, but are not limited to, the market prices of oil and gas, economic and competitive conditions, inflation rates, legislative and regulatory changes, financial market conditions, political and economic uncertainties of foreign governments, future business decisions, and other uncertainties, all of which are difficult to predict. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates. The drilling of exploratory wells can involve significant risks, including those related to timing, success rates and cost overruns. Lease and rig availability, complex geology and other factors can affect these risks. Although the Company makes use of futures contracts, swaps, options and fixed-price physical contracts to mitigate risk, fluctuations in oil and gas prices, or a prolonged period of low natural gas and crude oil prices, may substantially adversely affect the Company's financial position, results of operations and cash flows.

Mission Statement

Petroleum Development Corporation is committed to increasing shareholder value through growth of our natural gas businesses. We will pursue this goal by continuing to develop our existing properties, and by aggressively pursuing acquisitions that can add immediately to our reserves and production and provide additional development potential.

We remain focused on continuing to improve our financial position and resources in order to capitalize on emerging opportunities, and are dedicated to the protection of the environment in the development and operation of our properties.

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Financial and Operating Highlights

Income Statement (dollars in thousands)

	1998	1997	1996
Operating Revenues	**$82,974**	$73,878	$49,614
Net Income	**6,658**	7,587	3,549

Balance Sheet (dollars in thousands)

	1998	1997	1996
Properties and Equipment (net of DD&A)	**$65,391**	$43,569	$34,440
Long Term Debt	**$ —**	$ —	$ 5,320
Shareholder's Equity	**$62,747**	$55,766	$23,073

Per Share (dollars)

		1998	1997	1996
Net Income	1 Q	**$0.17**	$0.21	$0.11
	2 Q	**0.11**	0.12	0.06
	3 Q	**0.03**	0.12	0.04
	4 Q	**0.10**	0.16	0.10
	Total	**$0.41**	$0.61	$0.31
Book Value		**$4.05**	$3.66	$2.21
Market Price Range		**2 15/16-6 5/8**	2 7/8-11 7/16	1 5/16-6 3/16

Operating Statistics

	1998	1997	1996
Reserves (EBCF)	**80.99**	57.20	43.80
Gas Production (MMCF)	**2,453**	1,810	1,537
Reserves/Share (EMCF)	**5.2**	3.8	3.8

To Our Shareholders

Dear Friends

This is our thirtieth annual report to the shareholders of Petroleum Development Corporation. As the adjoining table reflects, a lot has changed over those thirty years. Revenues, expenses, assets, and shareholder equity are all orders of magnitude greater than when we began. In our 1969 annual report our accountants found it necessary to document depreciation of $31.57 for office equipment, and total depreciation of $542.06. That amount is less than the rounding error in our current statements.

For all the differences between this report and our first one, both share an enthusiasm about our business and the prospects for the future. As we begin our fourth decade as a public company we are experiencing some of the most exciting developments in our history. In a year when many oil and gas companies were forced to abandon growth plans because of low oil and gas prices, we were able to continue with our business plan because of our strong financial position.

As we said in our 1997 annual report, our primary objective for 1998 was "to continue to expand our natural gas reserves, production, and revenue." To accomplish this goal we nearly doubled our capital investment in 1998 from the prior year. About half of the investment came from internally generated funds and about half from the proceeds of our November 1997 stock sale. Two thirds of the investment was in new wells, and one third was spent for the acquisition of producing properties. Neither the new wells drilled nor the acquisitions were available to contribute to our results for the full year in 1998, so we expect to see an even greater contribution from these investments in 1999.

Then and Now
30 Years of History

	30 Years Ago	Now
Assets	$3,250,762	$111,300,400
Liabilities	209,530	48,533,700
Shareholder's Equity	3,041,232	62,746,700
Oil and Gas Sales	11,843	35,560,300
Depreciation, Depletion, and Amortization	542	3,253,600
Net Income (Loss)	(12,382)	6,658,000
Capital Investment	25,000	26,629,700

One element of the plan to achieve our growth objectives is geographic expansion from our Appalachian base. As part of this plan we drilled 86 wells in Michigan during 1998, and we are continuing to add to this total in 1999. We expect to see much more impact from these wells in 1999 as more projects are placed into production and as the dewatering process progresses on both the new and the older projects. In addition to Michigan we also began to build acreage positions in several areas in the Rocky Mountains during 1998, including Colorado, Utah, and Montana. We believe some or all of these projects will play important roles in our future plans.

The basic elements of our business strategy are set out in the adjoining box. We believe we are well equipped to pursue each of these elements of our strategy. We have been one of the most active drillers in the Northeast for a number of years, and have substantial expertise in drilling operations. We have made several successful

Our strategy includes five key elements to achieve our primary objective—expansion of our natural gas reserves, production, and revenue:

Expand drilling operations. In conjunction with our Company-sponsored partnerships increase the number of wells drilled and our average interest in those wells.

Acquire producing properties. Add wells in areas where we already operate to generate economies of scale for both the acquired wells, and wells we already own. Acquire wells in new areas to develop an operating and experience base that reduces risk and increases the probability of success for new operations.

Pursue geographic expansion. Identify and expand into areas where our expertise drilling and operating shallow natural gas wells can be successfully applied.

Reduce risks inherent in natural gas development and marketing. Continue to focus on shallow, relatively inexpensive natural gas wells, geographic diversification, gas price hedging, and acquisition of producing properties to manage the risk inherent in our business.

Expand strategic relationships. Develop properties in conjunction with Company sponsored public limited partnerships, to share administrative, overhead, and other costs as well as the risks of the projects. Benefit from the cost savings, as well as the greater engineering and geological capabilities our combined efforts can support.

acquisitions over the past several years and our systems can easily and quickly absorb significant additions. Our geographic expansion, first into Pennsylvania from our West Virginia base, and more recently into Michigan and beyond, is proceeding well. Our risk management programs are working, and our partnerships are sold through over 100 broker/dealer firms nationwide with sales broadly diversified.

With our 1998 drilling and acquisition activities and continued activity in 1999 the proceeds of our 1997 offering have been fully utilized. We plan to continue our growth in 1999 with funds generated by operations along with our available $20,000,000 line of credit with First National Bank of Chicago.

While our primary objective is profitable growth, we continue to place a high priority on being a good corporate citizen, with a particular focus on environmental responsibility. In 1998 the West Virginia Division of Environmental Protection once again recognized Petroleum Development Corporation for "Exemplary Performance in the Water Quality Management Program for the Oil & Gas Industry in planning, construction, and reclamation of well sites." We are proud of this performance, particularly given the high level of drilling activity engaged in by the Company.

We carried a backlog of over 100 wells into 1999. This work combined with our increasing oil and gas sales, should help us get off to a good start this year. We will continue to strive to make 1999 a year of new records for the Company.

Very truly yours,

James N. Ryan
Chairman and CEO

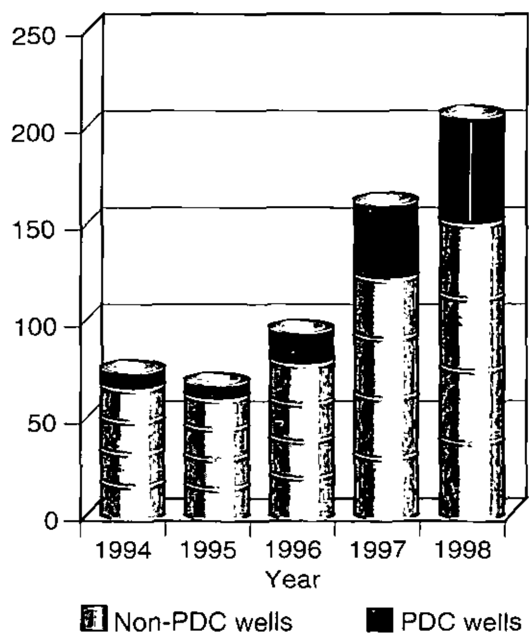
Steven R. Williams
President

Review of Operations

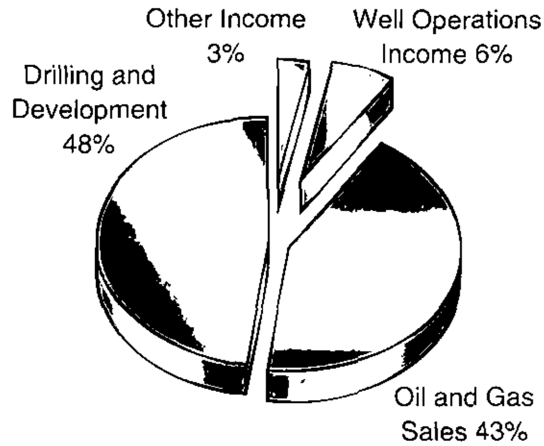
Petroleum Development Corporation's operating activities can be divided into three major areas: Drilling and Development, Oil and Gas Sales, and Well Operations. The chart at right shows the relative contribution of each of these areas to the revenues of the Company. In addition the Company realizes limited revenues from non-operating activities, principally interest on investments and partnership management fees.

The Company significantly increased both the size and scope of its operations during 1998. Proceeds from the Company's November 1997 stock offering were invested in drilling projects and acquisitions throughout the year. The Company also realized record drilling partnership sales that contributed to the increases. Each of the company's operating areas will continue to benefit from these investments in 1999 and beyond, particularly as the wells drilled and acquired in 1998 are available to contribute to Company results for the full year.

Successful Wells Drilled



Revenue Sources



Drilling and Development

Petroleum Development Corporation drilled a record 214 wells during 1998 including 203 successful wells and 11 dry holes. Of this total 128 wells were drilled in the Appalachian Basin and 86 wells in Michigan. The company retained an average interest in the wells of about 27% for a total of 55.34 net wells. Company sponsored partnerships purchased most of the balance of the wells. In comparison the company drilled a total of 168 wells in 1997, including 10 dry holes, and retained 38 net wells.

In most cases the Company acts as operator and manages the drilling and completion process, as well as operations when the wells are producing. Prospects are originated by or evaluated and selected by the Company's geological staff.

The wells drilled in 1998 were all targeted at shallow natural gas zones. In the Appalachian Basin typical well depths are in the 3000 to 6000 foot range, and targets are generally tight sand or shale reservoirs. In Michigan the Company's primary development is Antrim shale at around 1000 feet in depth. Most of the wells the Company drills are offsetting existing producing wells and are considered to be developmental in nature. Like western coal bed methane reservoirs, the Antrim shale must be dewatered before it can be effectively produced. This tends to delay peak production for periods ranging from six to eighteen months after production operations commence.

Leasing Activities

Petroleum Development obtains the rights to drill for natural gas in a number of ways and from a number of sources. If possible the company obtains leases directly from the oil and gas mineral owners. In other cases the Company purchases leases from lease brokers or other oil and gas companies, or farms out the right to drill. The company generally leases acreage that it plans to use for its own development activities, as opposed to leasing speculatively for potential resale.

The Company finished 1998 with an undeveloped lease position of 142,120 acres. The leasing activity is summarized in the table below:

Location	YE/97 Undeveloped	YE/98 Undeveloped Acres
Michigan	61,850	67,420
Ohio	1,300	1,300
Pennsylvania	17,700	18,600
Utah	—	39,500
West Virginia	32,000	15,300
Total	**112,850**	**142,120**

The lease acquisition process is directed by the Company's geologists to maximize the value of the acreage acquired. The geologists first evaluate an area for productive potential, after which the Company acquires leases in areas that meet its development criteria. Then, depending on the results of drilling, these areas may be expanded or modified to include additional productive acreage, or to exclude acreage that does not meet expectations.

Funding of Drilling Activity

The Company invests in new wells as the managing general partner of Company sponsored partnerships, as a joint venturer, or through a combination of the two methods. During 1998 the Company sponsored four publicly registered drilling partnerships which raised a total of $40.6 million, an increase of 14% from the $36.5 million raised in 1997.

Funds from the fourth 1997 partnership and the first three 1998 partnerships were used to drill wells in 1998. Funds from the final 1998 partnership, which closed December 31, were used to drill first quarter 1999 wells. Generally the Company has a 20% interest in the partnerships' revenues and expenses.

In Michigan and other new areas the Company is also participating in wells as a joint venture partner with the partnerships and others. This participation helps the partnerships to achieve certain of their financial goals, and allows PDC to carry a larger interest in those development activities.

In addition to the partnerships, the Company also has several other joint venture partners who participate in drilling in some of the development areas. These partners are currently carrying a 5% to 50% working interest in some of the wells.

The Company has registered a drilling program for 1998 through 2000 consisting of up to twelve partnerships and with maximum subscriptions of $150 million. Four of those partnerships, with total subscriptions of $40.6 million, began operations in 1998. The Company plans to continue to offer interests in the partnerships through a nationwide network of NASD broker/dealers numbering more than 100.

Funds for Petroleum Development Corporation's investment in the partnerships and joint ventures come from several sources. Operating profits from drilling activities, well operations, and oil and gas sales have historically provided the bulk of the Company's investment. During 1998 the Company had additional funds available from its 1997 sale of stock, as well as an available credit facility of $20 million with First National Bank of Chicago.

Michigan Drilling Operations

More than 5,000 natural gas wells have been drilled in Michigan since 1989, and the majority of those wells targeted the Antrim Shale as the producing formation. The productive shale area now extends across the northern part of the

Michigan Basin. Within the productive area low dry hole rates are the norm, although production can vary substantially from well to well. The Antrim Shale is typically developed in projects of ten or more wells that include the wells, water and gas gathering lines, compression and dehydration equipment, and water disposal facilities. When first drilled the Antrim Shale is generally water filled. The wells initially produce water at high rates along with small amounts of gas. As the shale dewaters, gas production increases and water production decreases for a typical period of 6-18 months before peak gas production rates are realized. Once the peak rate has been attained gas production begins a gradual decline which continues for the life of the wells.

During 1998 the Company drilled a total of 86 Michigan wells of which 83 were successful. As of the end of the year the company had six Antrim shale projects in varying stages of dewatering, and another four with facilities still under construction. The Company expects the production from all of these projects to increase in 1999, as the projects not yet in production are started up and as the dewatering process continues.

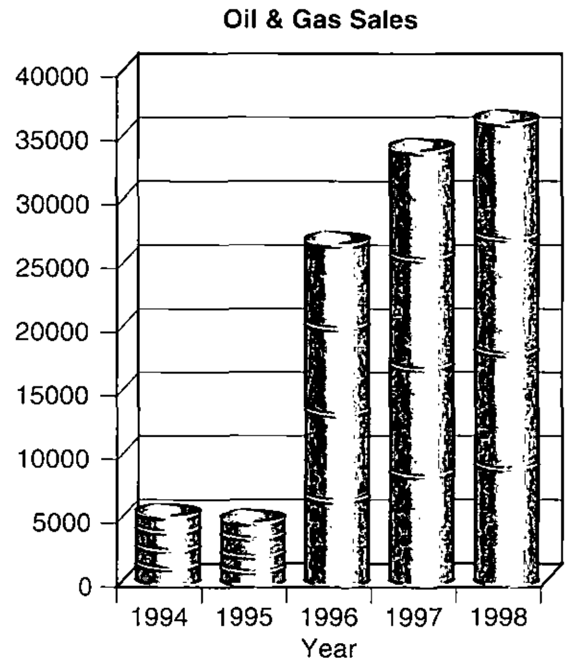
Appalachian Basin

A total of 128 Appalachian wells were drilled in 1998 targeted at the Devonian and Mississippian age productive formations. Of the total, 120 were successful. Drilling activities were conducted in Pennsylvania and West Virginia. Most of the 1998 wells were in production by the date of this report, and all should be in production by the end of the second quarter of 1999.

Production from Appalachian wells generally starts at its maximum level and declines slowly over time. Most of the new wells are in areas with no oil production and the wells produce only small amounts of water, if any. These combined characteristics result in low operating costs and long lives for wells, with an average well life of 25 years or more being quite common. As a result of the gradual decline rates a smaller percentage of new production is needed to maintain production rates than in areas with steeper decline rates.

Natural Gas Sales

The natural gas sales of Petroleum Development Corporation increased substantially during 1998 despite weaker natural gas prices. Oil sales, which are a minor component of the Company's sales, remained relatively constant. Sales of natural gas are attributable to natural gas marketing activities of subsidiaries Riley Natural Gas and the Paramount Pipeline as well as sales of gas produced by the Company's wells. Both areas recorded increases in performance during 1998.



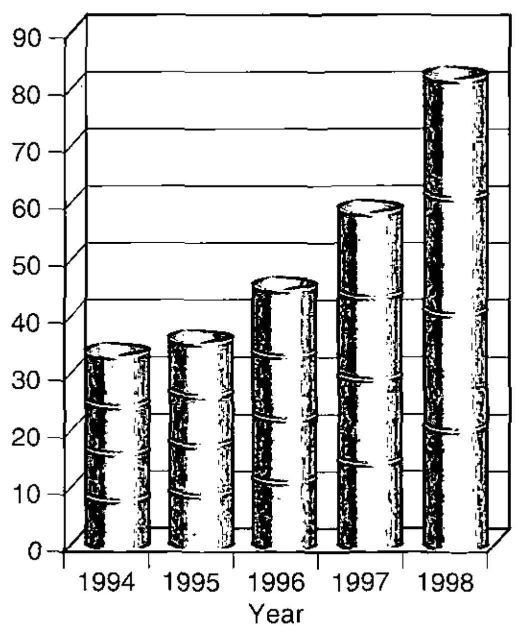
Marketing and Pipeline

Petroleum Development Corporation engages in gas marketing operations through two subsidiaries, Riley Natural Gas and Paramount Transmission Corporation. The company also markets gas to residential, commercial and industrial end-users in Ohio through subsidiary Paramount Natural Gas (a regulated Ohio gas distribution company). Combined sales of these entities increased by 6.4% to $35.6 million in 1998, despite significantly lower gas prices.

During 1998 the Company used commodity based derivative instruments (hedging) to manage a portion of its exposure to price volatility stemming from natural gas sales and marketing activity. The Company does not use natural gas futures for speculative purposes, and requires an underlying physical position. The effect of these hedges is to allow the Company to "lock in" fixed purchase or sales prices.

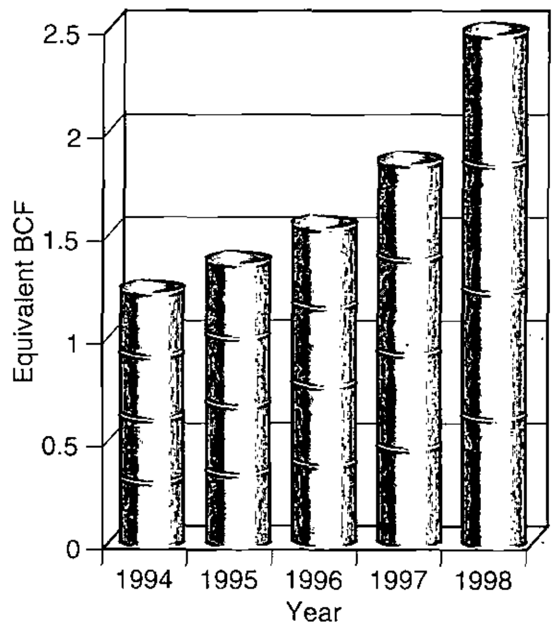
Production and Reserves

Using proceeds from the 1997 stock offering as well as internally generated funds the company made substantial additions to both production and reserves in 1998. The additions included 55.34 net new wells drilled by the Company and well interests added by purchase of producing wells. The acquired interests included an 80% working interest in 122 producing wells located in Pennsylvania; a 100% working interest in a 13 well Antrim Shale project in Michigan, and producing interests in a number of Company sponsored partnerships.



Gas reserves and production increased to record levels in 1998 as a result of these production acquisitions and new wells drilled by the Company. Total reserves increased 41% to 80.8 BCF with substantial additions in both the Appalachian and Michigan Basins. Proved developed reserves were increased 52%.

Natural gas production also increased by 35% in 1998 from 1.81 BCF to 2.453 BCF. These numbers included only a small amount of gas from Michigan wells many of which began production late in the year, and all of which are still in the dewatering phase. About half of the wells drilled during 1998 were drilled after the middle of the year, and as a result began production late in the year or in 1998. As a result of these factors the Company expects production to continue to increase in 1999. As in the past the Company produced only small amounts of oil.



Revenue from the sale of produced oil and gas (net of production costs) also increased in 1998 despite lower gas prices. The lower prices did mean that revenue increased only 14% compared to the 35 % increase in sales volumes.

Most of the Company's gas sales are made at spot market or market sensitive rates, and natural gas prices have been among the most volatile in commodities markets. As a result Petroleum Development Corporation is using commodities hedges to reduce price risk and create a more predictable cash flow stream as discussed above.

Future plans call for the Company to continue to stress increasing its gas reserves and production. As in 1998 this is to be accomplished by investment in new drilling projects and by purchasing existing producing properties. Both drilling and acquisitions will be concentrated either in areas where the Company has existing operations, or areas where the Company plans or has commenced new drilling operations. These new areas will also build on the Company's existing knowledge and experience. The Company plans to operate most if not all of new drilling and acquisition projects.

Well Operations

As of the end of 1998 the Company operated over 1,600 natural gas wells, and by the end of 1999 the number will almost certainly exceed 1,800. The Company owns an average working interest of about 43%, with the balance owned by the Company-sponsored partnerships and other joint venturers. The Company charges its partners a competitive industry rate for well operations, and while the per well profit is modest, aggregate cash flow from operations is a significant and steady source of cash flow for the Company. As the largest interest holder in the wells, the Company has a strong incentive to maximize production revenue for itself and its partners. A third party operator with little or no interest in the wells would not have the same incentive. The Company plans to continue to operate most newly drilled and acquired wells.

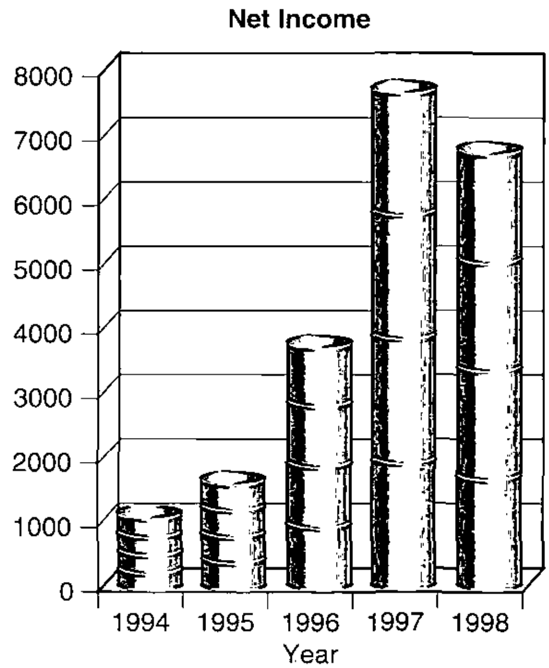
Financial Highlights

The financial performance of the company reflects both the operating successes and the challenges faced by oil and gas companies in 1998. Financial milestones for 1998 include record drilling revenues, oil and gas sales and well operations revenue. The bottom line unfortunately did not fare as well as the revenue line. Net income declined by 12% from $7,586,800 to $6,658,000. Per share earnings (diluted) declined from $.61 to $.41 per share. Several factors prevented the record revenue from translating into better income and per share numbers.

In the drilling area the Company's cost of drilling increased from 83%to 87% of revenue. Two of the key factors causing this cost increase were adverse weather conditions during our busy winter drilling period and start-up costs in our new drilling areas.

For Petroleum Development, as for most oil and gas companies, low energy prices also had an adverse impact on results. The industry generally suffered from low prices resulting from low demand associated with warm weather conditions (natural gas), and global oversupply and competition (oil). The average price of gas sold by the company declined from $2.88 per MCF in 1997 to $2.46 per MCF in 1998, or about 15%. Without the Company's hedging activities the decline would have been even greater.

The larger average number of shares outstanding during the year also reduced Per Share results. The average number of shares outstanding in 1998 was 15,505,680.



Selected Financial Data

	Year Ended December 31,				
	1998	1997	1996	1995	1994
Revenues					
Oil and gas well drilling operations	**$ 40,447,100**	$34,405,400	$18,698,200	$13,941,000	$15,190,200
Oil and gas sales	**35,560,300**	33,390,200	26,051,100	4,150,600	4,361,300
Well operations income	**4,581,000**	4,509,300	3,928,800	3,750,900	3,730,300
Other income	**2,385,200**	1,573,100	935,600	504,000	524,400
Total	**$ 82,973,600**	$73,878,000	$49,613,700	$22,346,500	$23,806,200
Costs and Expenses (excluding interest and depreciation, depletion and amortization)	**$ 71,094,900**	$61,219,600	$42,274,100	$18,042,300	$20,559,500
Interest Expense	**$ —**	$ 315,900	$ 380,000	$ 319,700	$ 300,200
Depreciation, Depletion and Amortization	**$ 3,253,600**	$ 2,660,300	$ 2,309,600	$ 2,152,100	$ 1,848,200
Net Income	**$ 6,658,000**	$ 7,586,800	$ 3,549,400	$ 1,481,500	$ 921,600
Basic earnings per common share	**$.43**	$.67	$.34	$.13	$.08
Diluted earnings per share	**$.41**	$.67	$.34	$.13	$.08
Average Common and Common Equivalent Shares Outstanding During the Year	**16,338,298**	12,540,165	11,542,315	11,611,164	12,115,612

	December 31,				
	1998	1997	1996	1995	1994
Total Assets	**$111,300,400**	$98,411,600	$63,604,200	$40,620,100	$38,325,300
Working Capital	**$ 1,524,800**	$16,483,200	$ (2,357,200)	$ (1,519,700)	$ (1,613,700)
Long-Term Debt, excluding current maturities	**$ —**	$ —	$ 5,320,000	$ 2,500,000	$ 3,100,000
Stockholders' Equity	**$ 62,746,700**	$55,766,100	$23,072,500	$19,920,900	$18,380,500

Management's Discussion and Analysis of Financial Condition and Results of Operations

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

Statements, other than historical facts, contained in this Annual Report on Form 10-K, including statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and Management's strategies, plans and objectives, are "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks and uncertainties incident to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of hedging activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

Results of Operations

Year Ended December 31, 1998 Compared with December 31, 1997

Revenues. Total revenues for the year ended December 31, 1998 were $83.0 million compared to $73.9 million for the year ended December 31, 1997, an increase of approximately $9.1 million, or 12.3%. Drilling revenues for the year ended December 31, 1998 were $40.4 million compared to $34.4 million for the year ended December 31, 1997, an increase of approximately $6.0 million, or 17.4%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1998 were $35.6 million compared to $33.4 million for the year ended December 31, 1997, an increase of approximately $2.2 million, or 6.6%. Such increase was due primarily to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. This increase in production was offset in part by lower average sales prices from the Company's producing properties and decreased natural gas purchased for resale. Well operations and pipeline income for the year ended December 31, 1998 was $4.6 million compared to $4.5 million for the year ended December 31, 1997, an increase of approximately $100,000, or 2.2%. Such increase resulted from an increase in the number of wells operated by the Company. Other income for the year ended December 31, 1998 was $2.4 million compared to $1.6 million for the year ended December 31, 1997, an increase of approximately $800,000 or 50.0%. Such increase was due to management fees earned on higher volumes of drilling partnerships and interest earned on higher average cash balances.

Costs and expenses. Costs and expenses for the year ended December 31, 1998 were $74.3 million compared to $64.2 million for the year ended December 31, 1997, an increase of approximately $10.1 million, or 15.7%. Oil and gas well drilling operations costs for the year ended December 31, 1998 were $35.0 million compared to $28.0 million for the year ended December 31, 1997, an increase of approximately $7.0 million, or 25.0%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1998 were $33.6 million compared to $30.9 million for the year ended December 31, 1997, an increase of approximately $2.7 million, or 8.7%. Such increase was due primarily to natural gas marketing activities of RNG along with production costs associated with the increased production from the Company's producing properties, offset in part by lower volumes of gas purchased for resale by the Company. General and administrative expenses for the year ended December 31, 1998 were $2.5 million compared to $2.3 million for the year ended December 31, 1997, an increase of approximately $200,000. Depreciation, depletion and amortization costs for the year ended December 31, 1998 were $3.3 million compared to $2.7 million for the year ended December 31, 1997, an increase of approximately $600,000 or 18.5%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs were eliminated after the Company extinguished the balance on its bank credit line in November, 1997.

Net income. Net income for the year ended December 31, 1998 was $6.7 million compared to $7.6 million for the year ended December 31, 1997, a decrease of approximately $900,000, or 11.8%.

Year Ended December 31, 1997
Compared with December 31, 1996

Revenues. Total revenues for the year ended December 31, 1997 were $73.9 million compared to $49.6 million for the year ended December 31, 1996, an increase of approximately $24.3 million, or 49.0%. Drilling revenues for the year ended December 31, 1997 were $34.4 million compared to $18.7 million for the year ended December 31, 1996, an increase of approximately $15.7 million, or 84.0%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1997 were $33.4 million compared to $26.1 million for the year ended December 31, 1996, an increase of approximately $7.3 million, or 28.0%. Such increase was due primarily to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. This increase was offset in part by lower average sales prices from the Company's producing properties and decreased natural gas purchased for resale. Well operations and pipeline income for the year ended December 31, 1997 were $4.5 million compared to $3.9 million for the year ended December 31, 1996, an increase of approximately $600,000, or 15.4%. Such increase resulted from an increase in the number of wells operated by the Company. Other income for the year ended December 31, 1997 was $1,573,000 compared to $936,000 for the year ended December 31, 1996, an increase of approximately $637,000 or 68.1%. Such increase was due to management fees earned on higher volumes of drilling partnerships, interest earned on higher average cash balances along with a gain on the sale of equipment.

Costs and expenses. Costs and expenses for the year ended December 31, 1997 were $64.2 million compared to $45.0 million for the year ended December 31, 1996, an increase of approximately $19.2 million, or 42.7%. Oil and gas well drilling operations costs for the year ended December 31, 1997 were $28.0 million compared to $15.8 million for the year ended December 31, 1996, an increase of approximately $12.2 million, or 77.2%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1997 were $30.9 million compared to $24.2 million for the year ended December 31, 1996, an increase of approximately $6.7 million, or 27.7%. Such increase was due primarily to natural gas purchases by RNG for resale and offset partially by lower volumes of natural gas purchased for resale.

Net income. Net income for the year ended December 31, 1997 was $7.6 million compared to $3.5 million for the year ended December 31, 1996, an increase of approximately $4.1 million, or 117.1%.

Year 2000 Issue

State of Readiness

The Year 2000 Issue is the risk that computer programs using two-digit data fields will fail to properly recognize the year 2000, with the result being business interruption due to computer system failures by the Company's software or hardware or that of government entities, service providers and vendors. The Company has assessed the extent of the Year 2000 Issues affecting the Company. The Company believes that the new computer system including operating software installed during 1998 along with modifications made by the Company's computer technicians have addressed the dating system flaw inherent in most operating systems. The Company has completed a remediation plan and believes it is currently fully Year 2000 Compliant.

The Company has initiated formal communications with its significant suppliers and service providers to determine the extent to which the Company may be vulnerable to their failure to correct their own Year 2000 issues. It is expected that full identification will be completed by April 30, 1999. To the extent that responses to Year 2000 readiness are unsatisfactory, the Company intends to take appropriate action, including identifying alternative suppliers and service providers who have demonstrated Year 2000 readiness.

Cost of Readiness

Expenditures related to Year 2000 remediation did not exceed $35,000. These expenditures include costs related to the data processing transition, a new computer system, purchase of software, modifications and implementation costs. A portion of these costs were capitalized and will be amortized over the estimated useful life of the asset beginning in the third quarter of 1998. The remainder of these costs have been expensed as incurred. Management believes that the cost to become Year 2000 Compliant is not material to the Company's financial position or results of operations.

Risks of Year 2000 Issues

The Company presently believes the Year 2000 Issue will not present a materially adverse risk to the Company's future consolidated results of operations, liquidity, and capital resources. However, if the level of timely compliance by key suppliers or service providers is not sufficient, the Year 2000 Issue could have a material impact on the Company's operations including, but not limited to, increased operating costs, loss of customers or suppliers, loss of accounting functions, including well revenue distributions, or other significant disruptions to the Company's business.

Contingency Plan

The Company has a contingency plan, and will implement it on systems that remains non-compliant as of December 31, 1999, if any.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations, capital raised through stock offerings and drilling partnerships, and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas from the Company's well interests, well drilling and operating activities for the Company's investor partners, natural gas gathering and transportation, and natural gas marketing. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with operating cash flow accruing to the Company to the extent payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Sales volumes of natural gas have continued to increase while natural gas prices fluctuate monthly. The Company's natural gas sales prices are subject to increase and decrease based on various market-sensitive indices. A major factor in the variability of these indices is the seasonal variation of demand for the natural gas, which typically peaks during the winter months. The volumes of natural gas sales are expected to continue to increase as a result of continued drilling activities and additional investment by the Company in oil and gas properties. The Company utilizes commodity-based derivative instruments (natural gas futures and option contracts traded on the NYMEX) as hedges to manage a portion of its exposure to this price volatility. The futures contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a three to twelve-month period.

The Company has a bank credit agreement with First National Bank of Chicago, which provides a borrowing base of $10.0 million, subject to adequate oil and natural gas reserves. At the request of the Company, the bank, at its sole discretion, may increase the borrowing base to $20.0 million. As of December 31, 1998, no balance is outstanding on the line of credit. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on December 31, 1999. The Company is currently working on an amendment with the bank to extend the expiration date of the credit agreement.

In September 1997, the Company completed a private offering of Common Stock pursuant to which it issued and sold 500,000 shares at a price of $4.00 per share and issued warrants for 125,000 shares of Common Stock exercisable during a two-year period ending September 15, 1999 at an exercise price of $6.00 per share, resulting in proceeds to the Company of $2.0 million. No registration rights were granted in connection with the securities issued in this offering.

In November 1997, the Company completed a public offering of 4,077,500 shares of its Common Stock at a price of $6.25 per share. Net proceeds to the Company of approximately $23 million from the sale of common stock is designated to fund development drilling on new and existing properties, potential acquisition of producing properties and general corporate purposes, including working capital and possible acquisitions of complementary businesses.

The Company closed four public drilling partnerships during 1998. The total amount received during 1998 was $40.9 million compared to $35.5 million for 1997, an increase of $5.4 million or 15.2%. The Company closed a record drilling program on December 31, 1998 in the amount of $20.6 million and will drill the wells during the first quarter 1999. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

On February 19, 1998, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1993. The Company purchased approximately $2.3 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1998. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On June 12, 1998 the Company purchased for $3.1 million a majority interest in the assets of Pemco Gas, Inc., a Pennsylvania producing company. The assets include 122 natural gas wells, 2,700 undeveloped acres, gathering systems, natural gas compressors and other facilities. The Company estimates that its interest includes 4.7 Bcf of natural gas reserves. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On November 16, 1998, the Company purchased all of the working interest in a 13 well Antrim Shale production unit and adjacent development locations in Montmorency County, Michigan. The Company estimates that the purchase includes approximately 4 Bcf of proved developed producing reserves and 1.5 Bcf of proved undeveloped reserves, with an acquisition cost of $2.8 million. The Company utilized capital received from its Public Offering to fund this purchase.

On January 29, 1999, the Company offered to purchase from the Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The total of the offer if accepted by all of the approximately 6,500 investors would be approximately $13.8 million. The offer expires on March 31, 1999. Management does not expect the entire amount of the offer to be accepted by the investors. The Company plans to utilize capital received from its Public Stock Offering to fund this purchase obligation.

The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

New Accounting Standards

During the fourth quarter of 1998, the Company adopted SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information* in its full year 1998 financial statements. SFAS No. 131 establishes standards for the way that public enterprises report information about operating segments in annual and interim financial statements. Because SFAS No. 131 has a disclosure-only effect on the notes to the Company's financial statements, adoption of SFAS No. 131 has no impact on the Company's result of operations or financial condition.

Statement of Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. Statement 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. The Company must adopt SFAS No. 133 by January 1, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and options contracts, outstanding at the date of adoption.

Quantitative and Qualitative Disclosure About Market Risk.

Market-Sensitive Instruments and Risk Management

The Company's primary market risk exposures are interest rate risk and commodity price risk. These exposures are discussed in detail below:

Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents. The Company has no interest rate risk related to long-term debt including current maturities, since no amounts were outstanding as of December 31, 1998. Interest-bearing cash and cash equivalents includes money market funds, certificates or deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 1998 is 13,769,100 with an average interest rate of 4.9 percent.

Commodity Price Risk

The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates. As a result, while these hedging arrangements are structured to reduce the Company's exposure to decreases in price associated with the hedging commodity, they also limit the benefit the Company might otherwise have received from price increases associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes. As of December 31, 1998, PDC had entered into a series of natural gas future contracts and options contracts. Open future contracts maturing in 1999 are for the purchase of 520,000 MMBtu of natural gas with a weighted average price of $2.15/MMBtu resulting in a total contract amount of $1,120,300, with a fair value of $(105,400). Open option contracts maturing in 1999 are for the purchase of 210,000 MMBtu of natural gas with a weighted average price of $.15 per MMBtu resulting in a total contract amount of $31,500 with a fair value of $45,800.

Independent Auditors' Report

The Stockholders and Board of Directors
Petroleum Development Corporation:

We have audited the consolidated financial statements of Petroleum Development Corporation and subsidiaries as listed in the accompanying index. In connection with our audits of the consolidated financial statements, we also have audited the financial statement schedule as listed in the accompanying index. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1998, in conformity with generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Pittsburgh, Pennsylvania
March 5, 1999

Consolidated Balance Sheets

December 31, 1998 and 1997

	1998	1997
ASSETS		
Current assets:		
Cash and cash equivalents (includes restricted cash of $156,200 and $926,100, respectively)	**$ 34,894,600**	$46,561,000
Notes and accounts receivable	**6,024,100**	4,923,400
Inventories	**702,400**	297,900
Prepaid expenses	**2,387,500**	2,076,500
Total current assets	**44,008,600**	53,858,800
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	**81,592,700**	57,614,900
Pipelines	**7,669,700**	7,007,800
Transportation and other equipment	**2,332,200**	2,014,000
Land and buildings	**1,152,700**	1,155,500
	92,747,300	67,792,200
Less accumulated depreciation, depletion and amortization	**27,356,700**	24,222,900
	65,390,600	43,569,300
Other assets	**1,901,200**	983,500
	$111,300,400	$98,411,600

	1998	1997
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 11,218,900**	$ 9,792,300
Accrued taxes	**—**	367,000
Other accrued expenses	**1,959,900**	2,265,000
Advances for future drilling contracts	**28,320,800**	23,291,600
Funds held for future distribution	**984,200**	1,659,700
Total current liabilities	**42,483,800**	37,375,600
Other liabilities	**2,233,500**	1,684,000
Deferred income taxes	**3,836,400**	3,585,900
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share; authorized 50,000,000 shares; issued and outstanding 15,510,762 and 15,245,758	**155,100**	152,500
Additional paid-in capital	**31,925,400**	31,617,600
Warrants outstanding	**46,300**	46,300
Retained earnings	**30,672,200**	24,014,200
Unamortized stock award	**(52,300)**	(64,500)
Total stockholders' equity	**62,746,700**	55,766,100
	$111,300,400	$98,411,600

See accompanying notes to consolidated financial statements.

Consolidated Statements of Income

Years Ended December 31, 1998, 1997 and 1996

	1998	1997	1996
Revenues:			
Oil and gas well drilling operations	**$40,447,100**	$34,405,400	$18,698,200
Oil and gas sales	**35,560,300**	33,390,200	26,051,100
Well operations and pipeline income	**4,581,000**	4,509,300	3,928,800
Other income	**2,385,200**	1,573,100	935,600
	82,973,600	73,878,000	49,613,700
Costs and expenses:			
Cost of oil and gas well drilling operations	**35,047,500**	28,033,200	15,779,800
Oil and gas purchases and production cost	**33,556,900**	30,867,600	24,190,300
General and administrative expenses	**2,490,500**	2,318,800	2,304,000
Depreciation, depletion and amortization	**3,253,600**	2,660,300	2,309,600
Interest	**—**	315,900	380,000
	74,348,500	64,195,800	44,963,700
Income before income taxes	**8,625,100**	9,682,200	4,650,000
Income taxes	**1,967,100**	2,095,400	1,100,600
Net income	**$ 6,658,000**	$ 7,586,800	$ 3,549,400
Basic earnings per common share	**$.43**	$.67	$.34
Diluted earnings per common and common equivalent share	**$.41**	$.61	$.31

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity

Years Ended December 31, 1998, 1997 and 1996

	Common stock issued						
	Number of shares	Amount	Additional paid-in capital	Warrants outstanding	Retained earnings	Unamortized stock award	Total
Balance, December 31, 1995	11,208,627	$112,100	$ 7,019,800	$ —	$12,878,000	$(89,000)	$19,920,900
Issuance of common stock:							
Exercise of employee stock options	230,699	2,300	166,100	—	—	—	168,400
Purchase of subsidiary	236,094	2,300	446,800	—	—	—	449,100
Amortization of stock award						12,200	12,200
Repurchase and cancellation of treasury stock	(1,214,667)	(12,100)	(1,015,400)	—	—	—	(1,027,500)
Net income	—	—	—	—	3,549,400	—	3,549,400
Balance December 31, 1996	10,460,753	$104,600	$ 6,617,300	—	$16,427,400	$(76,800)	$23,072,500
Issuance of common stock:							
Stock offerings	4,577,500	45,800	24,903,600	46,300	—	—	24,995,700
Exercise of employee stock options	207,505	2,100	96,700	—	—	—	98,800
Amortization of stock award						12,300	12,300
Net income	—	—	—	—	7,586,800	—	7,586,800
Balance December 31, 1997	15,245,758	$152,500	$31,617,600	$46,300	$24,014,200	$(64,500)	$55,766,100
Issuance of common stock:							
Exercise of employee stock options	324,333	3,200	300,800	—	—	—	304,000
Amortization of stock award	—	—	—	—	—	12,200	12,200
Repurchase and cancellation of treasury stock	(59,329)	(600)	(303,400)	—	—	—	(304,000)
Income tax benefit from the exercise of stock options	—	—	310,400	—	—	—	310,400
Net income	—	—	—	—	6,658,000	—	6,658,000
Balance December 31, 1998	15,510,762	$155,100	$31,925,400	$46,300	$30,672,200	$(52,300)	$62,746,700

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years Ended December 31, 1998, 1997 and 1996

	1998	1997	1996
Cash flows from operating activities:			
Net income	**$ 6,658,000**	$ 7,586,800	$ 3,549,400
Adjustment to net income to reconcile to cash provided by operating activities:			
Deferred income taxes	**244,000**	107,700	213,900
Depreciation, depletion and amortization	**3,253,600**	2,660,300	2,309,600
Disposition of leasehold acreage	**196,200**	187,200	151,700
Employee compensation paid in stock	**12,200**	12,300	17,900
(Increase) decrease in notes and accounts receivable	**(1,100,700)**	1,772,600	(1,480,600)
(Increase) decrease in inventories	**(404,500)**	269,300	(349,300)
(Increase) decrease in prepaid expenses	**(600)**	(998,200)	203,300
Increase in other assets	**(911,200)**	(453,000)	(226,400)
Increase in accounts payable and accrued expenses	**1,304,000**	1,298,400	3,938,200
Increase in advances for future drilling contracts	**5,029,200**	4,894,600	8,327,400
(Decrease) increase in funds held for future distribution	**(675,500)**	795,700	160,000
Other	**18,700**	(39,600)	90,700
Total adjustments	**6,965,400**	10,507,300	13,356,400
Net cash provided by operating activities	**13,623,400**	18,094,100	16,905,800
Cash flows from investing activities:			
Capital expenditures	**(26,629,700)**	(13,675,100)	(10,415,500)
Proceeds from sale of leases	**1,283,600**	1,710,900	655,400
Proceeds from sale of fixed assets	**56,300**	87,600	10,800
Net cash acquired from purchase of subsidiary	**—**	—	1,450,000
Net cash used in investing activities	**(25,289,800)**	(11,876,600)	(8,299,300)
Cash flows from financing activities:			
Proceeds from debt	**—**	—	4,200,000
Proceeds from issuance of stock	**—**	25,048,100	135,300
Purchase of treasury stock	**—**	—	(1,000,000)
Retirement of debt	**—**	(5,320,000)	(1,380,000)
Net cash provided by financing activities	**—**	19,728,100	1,955,300
Net (decrease) increase in cash and cash equivalents	**(11,666,400)**	25,945,600	10,561,800
Cash and cash equivalents, beginning of year	**46,561,000**	20,615,400	10,053,600
Cash and cash equivalents, end of year	**$34,894,600**	$46,561,000	$20,615,400

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years Ended December 31, 1998, 1997 and 1996

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Petroleum Development Corporation and its wholly owned subsidiaries. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its prorata share of assets and liabilities and revenues and expenses, respectively, of the limited partnerships in which it participates.

The Company is involved in three business segments. The segments are drilling and development, natural gas sales and well operations. (See Note 18)

The Company grants credit to purchasers of oil and gas and the owners of managed properties, substantially all of whom are located in West Virginia, Tennessee, Pennsylvania, Ohio and Michigan.

Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

Exploration and development costs are accounted for by the successful efforts method.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each years calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, are capitalized.

Unproved properties are assessed on a property-by-property basis and properties considered to be impaired are charged to expense when such impairment is deemed to have occurred.

Costs of proved properties, including leasehold acquisition, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

Upon sale or retirement of complete units of depreciable or depletable property, the net cost thereof, less proceeds or salvage value, is credited or charged to income. Upon retirement of a partial unit of property, the cost thereof is charged to accumulated depreciation and depletion.

Based on the Company's experience, management believes site restor-ation, dismantlement and abandonment costs net of salvage to be immaterial in relation to operating costs. These costs are being expensed when incurred.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. These assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. An impairment loss based on estimated fair value is recorded when the review indicates that the related expected future net cash flow (undiscounted and without interest charges) is less than the carrying amount of the asset.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds applied thereto and any resulting gain or loss is reflected in income.

Buildings

Buildings are carried at cost and depreciated on the straight-line method over estimated useful lives of 30 years.

Advances for Future Drilling Contracts

Represents funds received from Partnerships and other joint ventures for drilling activities which have not been completed and accordingly have not yet been recognized as income in accordance with the Company's income recognition policies.

Retirement Plans

The Company has a 401-K contributory retirement plan (401-K Plan) covering full-time employees. The Company provides a discretionary matching of employee contributions to the plan.

The Company also has a profit sharing plan covering full-time employees. The Company's contributions to this plan are discretionary.

The Company has a deferred compensation arrangement covering executive officers of the Company as a supplemental retirement benefit.

The Company has established split-dollar life insurance arrangements with certain executive officers. Under these arrangements, advances are made to these officers equal to the premiums due. The advances are collateralized by the cash surrender value of the policies. The Company records as other assets its share of the cash surrender value of the policies.

Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

Income Taxes

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Derivatives

Gains and losses related to qualifying hedges of firm commitments or anticipated transactions through the use of natural gas futures and option contracts are deferred and recognized in income or as adjustments of carrying amounts when the underlying hedged transaction occurs. In order for futures contracts to qualify as a hedge, there must be sufficient correlation to the underlying hedged transaction. The change in the fair value of derivative instruments which do not qualify for hedging are recognized into income currently.

Stock Compensation

On January 1, 1996, the Company adopted SFAS No. 123, "Accounting for Stock- Based Compensation," which permits entities to recognize as expense over the vesting period the fair value of all stock-based awards on the date of grant. Alternatively, SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. See note 5 to the financial statements.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with generally accepted accounting principles. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties.

New Accounting Standards

During the fourth quarter of 1998, the Company adopted SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information* in its full year 1998 financial statements. SFAS No. 131 establishes standards for the way that public enterprises report information about operating segments in annual and interim financial statements. Because SFAS No. 131 has a disclosure-only effect on the notes to the Company's financial statements, adoption of SFAS No. 131 has no impact on the Company's result of operations or financial condition.

Statement of Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. Statement 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. The Company must adopt SFAS No. 133 by January 1, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS

No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and option contracts, outstanding at the date of adoption.

(2) NOTES AND ACCOUNTS RECEIVABLE

Included in other assets are noncurrent notes and accounts receivable as of December 31, 1998 and 1997, in the amounts of $617,870 and $22,522 net of the allowance for doubtful accounts of $129,800 and $129,800, respectively.

The allowance for doubtful current accounts receivable as of December 31, 1998 and 1997 was $144,800 and $145,600, respectively.

(3) LONG-TERM DEBT

On March 13, 1997, the Company amended and restated its bank credit agreement with First National Bank of Chicago, which provides a borrowing base of $10.0 million, subject to adequate oil and natural gas reserves. At the request of the Company, the bank, at its sole discretion, may increase the borrowing base to $20.0 million. As of December 31, 1998, the balance available under the line was $10.0 million. The Company is required to pay a commitment fee of 1/8% to 1/4% on the unused portion of the credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on December 31, 1999. The Company is currently working on an amendment with the bank to extend the expiration date of the credit agreement.

As of December 31, 1998 and 1997 there was no balance outstanding. Any amounts outstanding under the credit agreement are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends.

(4) INCOME TAXES

The Company's provision for income taxes consisted of the following:

	1998	1997	1996
Current:			
Federal	**$1,197,800**	$1,349,600	$545,600
State	**525,300**	638,100	341,100
Total current income taxes	**1,723,100**	1,987,700	886,700
Deferred:			
Federal	**(500)**	(32,100)	165,800
State	**244,500**	139,800	48,100
Total deferred income taxes	**244,000**	107,700	213,900
Total taxes	**$1,967,100**	$2,095,400	$1,100,600

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 34 percent to pretax income from continuing operations as a result of the following:

	1998 Amount	1997 Amount	1996 Amount
Computed "expected" tax	**$2,932,500**	$3,291,900	$1,581,000
State income tax	**508,100**	513,400	249,900
Percentage depletion	**(343,400)**	(263,500)	(205,800)
Nonconventional source fuel credit	**(696,700)**	(846,400)	(510,500)
Adjustments to valuation allowance	**(473,200)**	(565,200)	—
Other	**39,800**	(34,800)	(14,000)
	$1,967,100	$2,095,400	$1,100,600

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 1998 and 1997 are presented below:

	1998	1997
Deferred tax assets:		
Drilling notes, principally due to allowance for doubtful accounts	**$ 109,200**	$ 110,800
Alternative minimum tax credit carryforwards (Section 29)	**1,783,000**	1,413,400
Deferred Compensation	**968,500**	710,300
Other	**256,900**	170,300
Total gross deferred tax assets	**3,117,600**	2,404,800
Less valuation allowance	**(375,000)**	(848,200)
Deferred tax assets	**2,742,600**	1,556,600
Less current deferred tax assets (included in prepaid expenses)	**(818,800)**	(713,600)
Net non-current deferred tax assets	**1,923,800**	843,000
Deferred tax liabilities:		
Plant and equipment, principally due to differences in depreciation and amortization	**(5,760,200)**	(4,428,900)
Total gross deferred tax liabilities	**(5,760,200)**	(4,428,900)
Net deferred tax liability	**$(3,836,400)**	$(3,585,900)

The Company has evaluated each deferred tax asset and has provided a valuation allowance where it is believed it is more likely than not that some portion of the asset will not be realized. The valuation allowance relates principally to the alternative minimum tax credit carryforwards (Section 29).

The net changes in the total valuation allowance were for the year ended December 31, 1998 a decrease of $473,200 and a decrease of $782,300 for the year ended December 31, 1997.

At December 31, 1998, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately $1,783,000 which are available to reduce future federal regular income taxes over an indefinite period.

(5) COMMON STOCK

Options

Options amounting to 20,000 and 500,000 shares were granted during 1998 and 1997, respectively, to certain employees and directors under the Company's Stock Option Plans. These options were granted with an exercise price equal to market value as of the date of grant and vest over a two year period. The outstanding options expire from 2000 to 2007.

The estimated fair value of the options granted during 1998 and 1997 was $3.92 and $3.30 per option. The fair value was estimated using the Black- Scholes option pricing model with the following assumptions for the 1998 and 1997 grant, respectively: risk-free interest rate of 5.9% and 6.3%, expected dividend yield of 0%, expected volatility of 58.0% and 57.4% and expected life of 7 years.

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 1995	1,852,650	$0.91	.50-1.63
Granted	—		
Exercised	(230,000)	$0.72	.50-1.125
Expired	(40,000)	$0.80	.50-1.625
Outstanding December 31, 1996	1,582,650	$0.94	.50-1.625
Granted	500,000	$5.13	5.13-5.13
Exercised	(210,000)	$0.58	.50-1.13
Expired	—	$ —	—
Outstanding December 31, 1997	1,872,650	$2.10	.94-5.13
Granted	20,000	$6.13	6.13-6.13
Exercised	(324,333)	$0.94	.94-.94
Expired	—	$ —	—
Outstanding December 31, 1998	**1,568,317**	**$2.39**	**.94-6.13**

As of December 31, 1998, there were 1,048,317 options outstanding and exercisable in the $.94 to $1.63 exercise price range which have a weighted average remaining contractual life of 3.5 years and weighted average exercise price of $1.01. Also as of December 31, 1998 there were 520,000 options outstanding at a $5.13 to $6.13 exercise price range having weighted average remaining contractual life of 8.6 years and weighted average exercise price of $5.16. As of December 31, 1998 half of these options were exercisable.

The Company accounts for its stock-based compensation plans under APB 25. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. Had compensation cost been determined under the provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	1998		1997	
	As Reported	**Pro Forma**	As Reported	Pro Forma
Net income	**$6,658,000**	**$5,918,800**	$7,586,800	$7,163,600
Basic earnings per share	**$ .43**	**$ .38**	$ .67	$ .64
Diluted earnings per share	**$ .41**	**$ .37**	$ .61	$ .58

Stock Redemption Agreement

The Company has stock redemption agreements with three officers of the Company. The agreements require the Company to maintain life insurance on each executive in the amount of $1,000,000. The agreements provide that the Company shall utilize the proceeds from such insurance to purchase from such executives' estates or heirs, at their option, shares of the Company's stock. The purchase price for the outstanding common stock is to be based upon the average closing asked price for the Company's stock as quoted by NASDAQ during a specified period. The Company is not required to purchase any shares in excess of the amount provided for by such insurance.

Stock Purchase

On January 31, 1996, the Company purchased 1,200,000 shares of its common stock pursuant to an option agreement. The option was obtained in connection with a debt restructuring in 1990. The company utilized its' revolving credit line to acquire the shares for $1,000,000 or $0.83 a share. The shares representing approximately 11% of the outstanding stock at the date of acquisition were retired by the Company.

Stock Offerings

In September 1997, the Company completed a private offering of Common Stock pursuant to which it issued and sold 500,000 shares at a price of $4.00 per share and issued warrants for 125,000 shares of Common Stock exercisable during a two-year period ending September 15, 1999 at an exercise price of $6.00 per share, resulting in proceeds to the Company of $2.0 million. No registration rights were granted in connection with the securities issued in this offering.

In November 1997, the Company completed a public offering of 4,077,500 shares of its Common Stock at a price of $6.25 per share. Net proceeds to the Company of approximately $23 million from the sale of common stock is designated to fund development drilling on new and existing properties, potential acquisition of producing properties and general corporate purposes, including working capital and possible acquisitions of complementary businesses.

(6) EMPLOYEE BENEFIT PLANS

The Company made 401-K Plan contributions of $202,600, $171,300 and $139,800 for 1998, 1997 and 1996, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $17,000, $15,500 and 50,000 to the plan in cash during 1998, 1997 and 1996, respectively.

During 1998, 1997 and 1996 the Company expensed and established a liability for $90,000 each year under a deferred compensation arrangement with the executive officers of the Company.

In 1995, a total of 90,000 restricted shares of the Company's common stock were granted to certain employees and available to them upon retirement. The market value of shares awarded was $101,300. This amount was recorded as unamortized stock award and is shown as a separate component of stockholders' equity. The unamortized stock award is being amortized to expense over the employees' expected years to retirement and amounted to $12,200, $12,300 and $12,200 in 1998, 1997 and 1996, respectively.

At December 31, 1998 and 1997, the Company has recorded as other assets $240,000 and $180,000, respectively as its share of the cash surrender value of the life insurance pledged as collateral for the payment of premiums on split-dollar life insurance policies owned by certain executive officers.

(7) EARNINGS PER SHARE

In 1997, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 128, Earnings per share. All periods presented have been restated to conform to SFAS No. 128.

Basic earnings per share is based on the weighted average number of common share outstanding of 15,505,680 for 1998, 11,278,800 for 1997 and 10,449,137 for 1996.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,338,298 for 1998, 12,540,165 for 1997 and 11,542,315 for 1996. Stock options are considered to be common stock equivalents and, to the extent appropriate, have been added to the weighted average common shares outstanding.

(8) TRANSACTIONS WITH AFFILIATES

As part of its duties as well operator, the Company received $22,997,300 in 1998, $22,985,400 in 1997 and $18,234,200 in 1996 representing proceeds from the sale of oil and gas and made distributions to investor groups according to their working interests in the related oil and gas properties. The Company provided oil and gas well drilling services to affiliated partnerships, substantially all of the Company's oil and gas well drilling operations was for such partnerships. The Company also provided related services of operation of wells, reimbursement of syndication costs, management fees, tax return preparation and other services relating to the operation of the partnerships. The Company received $9,621,700 in 1998, $8,113,000 in 1997 and $6,435,700 in 1996 for those services.

During 1998, 1997 and 1996, the Company paid $30,000, $63,800 and $35,400, respectively to the Corporate Secretary's law firm for various legal services.

(9) COMMITMENTS AND CONTINGENCIES

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. No customer accounted for more than 10.0% of total revenues in 1998. One customer, Hope Gas, Inc., a regulated public utility accounted for 12.0% and 16.1% of total revenue in 1997 and 1996, respectively.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately $1.3 million. The Company has adequate capital to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

(10) SUPPLEMENTAL DISCLOSURE OF CASH FLOWS

The Company paid $380,000 and $319,700 for interest in 1997 and 1996, respectively. The Company paid income taxes in 1998, 1997 and 1996 in the amounts of $2,349,100, $1,932,500 and $664,300, respectively.

(11) ACQUISITIONS

On April 1, 1996, the Company acquired Riley Natural Gas Company (RNG), a privately held gas marketing company in a stock for stock exchange accounted for as a purchase. The acquisition has substantially increased the Company's capabilities in the natural gas marketing area. PDC issued 236,094 shares with a market value of $449,100, for 100% of the outstanding common stock of RNG. Key employees of RNG have entered into employment contracts with PDC to assure the continuity of RNG's gas marketing operations.

On August 6, 1996 the Company purchased an interest in 188 oil and gas wells in West Virginia. The Company utilized its revolving credit line to finance the purchase. The purchase increased the Company's oil and gas reserves by 4.3 Bcf of natural gas and 27,000 barrels of oil, added 12,000 acres of leases to its leasehold inventory and increased the Company's gathering systems by forty-nine miles. The purchase price was $3.3 million.

On February 19, 1998, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1993. The Company purchased approximately $2.3 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1998. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On June 12, 1998 the Company purchased for $3.1 million a majority interest in the assets of Pemco Gas, Inc., a Pennsylvania producing company. The assets include 122 natural gas wells, 2,700 undeveloped acres, gathering systems, natural gas compressors and other facilities. The Company estimates that its interest includes 4.7 Bcf of natural gas reserves. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On November 16, 1998, the Company purchased all of the working interest in a 13 well Antrim Shale production unit and adjacent development locations in Montmorency County, Michigan. The Company estimates that the purchase includes approximately 4 Bcf of proved developed producing reserves and 1.5 Bcf of proved undeveloped reserves, with an acquisition cost of approximately $2.8 million. The Company utilized capital received from its Public Stock Offering to fund this purchase.

(12) DERIVATIVES AND HEDGING ACTIVITIES

The company utilizes commodity based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its integrated natural gas production and marketing activities. These instruments consist of natural gas futures and option contracts traded on the New York Mercantile Exchange. The futures and option contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a 12 month period. The Company does not hold or issue derivatives for trading or speculative purposes.

As of December 31, 1998 and 1997, the Company had futures contracts for the purchase of $1,120,300 and sale of $4,599,700 of natural gas, respectively. While these contracts have nominal carrying value, their fair value, represented by the estimated amount that would be received upon termination of the contracts, based on market quotes, was a net value of $(105,400) at December 31, 1998 and $277,200 at December 31, 1997.

As of December 31, 1998, the Company had option contracts totalling $31,500 for the purchase of natural gas with a fair value of $45,800.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 1998 and 1997, cash in the amount of $156,200 and $926,100 was on deposit.

(13) COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below:

	Years Ended December 31,		
	1998	1997	1996
Property acquisition cost:			
Proved undeveloped properties	**$ 1,903,200**	$ 3,109,000	$ 543,600
Producing properties	**8,679,000**	85,100	3,211,800
Development costs	**14,902,500**	9,863,200	5,344,900
	$25,484,700	$13,057,300	$9,100,300

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells and to provide facilities to extract, treat, gather and store oil and gas.

(14) OIL AND GAS CAPITALIZED COSTS

Aggregate capitalized costs for the Company related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	December 31,	
	1998	1997
Proved properties:		
Tangible well equipment	**$46,722,500**	$31,820,100
Intangible drilling costs	**28,379,200**	19,700,200
Well equipment leased to others	**4,063,600**	4,063,600
Undeveloped properties	**2,427,400**	2,031,000
	81,592,700	57,614,900
Less accumulated depreciation, depletion and amortization	**20,395,400**	17,828,500
	$61,197,300	$39,786,400

(15) RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The results of operations for oil and gas producing activities (excluding marketing) are presented below:

	Years Ended December 31,		
	1998	*1997*	*1996*
Revenue:			
Oil and gas sales	**$6,121,700**	$5,363,600	$4,674,900
Expenses:			
Production costs	**1,516,700**	1,206,000	963,600
Depreciation, depletion and amortization	**2,392,000**	1,629,900	1,248,200
	3,908,700	2,835,900	2,211,800
Results of operations for oil and gas producing activities before provision for income taxes	**2,213,000**	2,527,700	2,463,100
Provision for income taxes	**398,600**	567,800	519,600
Results of operations for oil and gas producing activities (excluding corporate over-head and interest costs)	**$1,814,400**	$1,959,900	$1,943,500

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including such costs as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and other production taxes. In addition, production costs include administrative expenses and depreciation applicable to support equipment associated with these activities.

Depreciation, depletion and amortization expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment.

The provision for income taxes is computed at the statutory federal income tax rate and is reduced to the extent of permanent differences, such as investment tax and non-conventional source fuel tax credits and statutory depletion allowed for income tax purposes.

(16) NET PROVED OIL AND GAS RESERVES (UNAUDITED)

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineer, Wright & Company, Inc. at December 31, 1998, 1997 and 1996. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Oil (BBLS)		
	1998	1997	1996
Proved developed and undeveloped reserves:			
Beginning of year	**45,000**	81,000	140,000
Revisions of previous estimates	**(10,000)**	(27,000)	(30,000)
Beginning of year as revised	**35,000**	54,000	110,000
Dispositions	**—**	—	(49,000)
Acquisitions	**2,000**	—	27,000
Production	**(8,000)**	(9,000)	(7,000)
End of year	**29,000**	45,000	81,000
Proved developed reserves:			
Beginning of year	**45,000**	81,000	140,000
End of year	**29,000**	45,000	81,000

	Gas (MCF)		
	1998	1997	1996
Proved developed and undeveloped reserves:			
Beginning of year	**57,243,000**	43,312,000	33,829,000
Revisions of previous estimates	**(3,517,000)**	875,000	(1,037,000)
Beginning of year as revised	**53,726,000**	44,187,000	32,792,000
New discoveries and extensions	**23,552,000**	2,489,000	2,613,000
Dispositions to partnerships	**(6,009,000)**	—	(127,000)
Acquisitions, net of sales to partnerships in 1997 and 1996	**12,003,000**	12,377,000	9,529,000
Production	**(2,453,000)**	(1,810,000)	(1,495,000)
End of year	**80,819,000**	57,243,000	43,312,000
Proved developed reserves:			
Beginning of year	**42,411,000**	35,516,000	29,326,000
End of year	**64,562,000**	42,411,000	35,516,000

(17) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND GAS RESERVES (UNAUDITED)

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

	Years Ended December 31,		
	1998	1997	1996
Future estimated cash flows	**$186,598,000**	$159,618,000	$193,800,000
Future estimated production and development costs	**(95,670,000)**	(69,265,000)	(59,806,000)
Future estimated income tax expense	**(20,322,000)**	(20,781,000)	(33,499,000)
Future net cash flows	**70,606,000**	69,572,000	100,495,000
10% annual discount for estimated timing of cash flows	**(40,412,000)**	(41,636,000)	(66,233,000)
Standardized measure of discounted future estimated net cash flows	**$ 30,194,000**	$ 27,936,000	$ 34,262,000

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Years Ended December 31,		
	1998	1997	1996
Sales of oil and gas production, net of production costs	**$ (4,605,000)**	$ (4,158,000)	$ (3,711,000)
Net changes in prices and production costs	**(23,083,000)**	(63,573,000)	42,384,000
Extensions, discoveries and improved recovery, less related cost	**18,615,000**	3,705,000	9,659,000
Dispositions to partnerships	**(5,762,000)**	—	—
Acquisitions, net of sales to partnerships in 1997 and 1996	**13,938,000**	13,299,000	17,775,000
Development costs incurred during the period	**14,903,000**	9,863,000	5,345,000
Revisions of previous quantity estimates	**(5,605,000)**	2,332,000	(2,902,000)
Changes in estimated income taxes	**459,000**	12,718,000	(13,495,000)
Accretion of discount	**1,224,000**	24,597,000	(37,107,000)
Other	**(7,826,000)**	(5,109,000)	(4,746,000)
	$ 2,258,000	$ (6,326,000)	$ 13,202,000

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

(18) BUSINESS SEGMENTS (THOUSANDS)

PDC's operating activities can be divided into three major segments: drilling and development, natural gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to residential, commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 1998, 1997 and 1996 is as follows:

	1998	1997	1996
Revenues			
Drilling and Development	**$ 40,447**	$34,406	$18,698
Natural Gas Sales	**35,560**	33,390	26,051
Well Operations	**4,581**	4,509	3,929
Unallocated amounts (1)	**2,385**	1,573	936
Total	**$ 82,973**	$73,878	$49,614

(1) Includes interest on investments and partnership management fees which are not allocated in assessing segment performance.

	1998	1997	1996
Segment Income Before Income Taxes			
Drilling and Development	**$ 5,400**	$ 6,372	$ 2,918
Natural Gas Sales	**2,064**	2,780	2,303
Well Operations	**1,372**	1,701	1,302
Unallocated amounts (2)			
General and Administrative expenses	**(2,491)**	(2,660)	(2,310)
Interest expense	**—**	(316)	(380)
Other (1)	**2,280**	1,805	817
Total	**$ 8,625**	$ 9,682	$ 4,650

(2) Items which are not allocated in assessing segment performance.

	1998	1997	1996
Segment Assets			
Drilling and Development	**$ 27,288**	$22,110	$15,957
Natural Gas Sales	**65,256**	45,888	37,504
Well Operations	**7,136**	5,953	5,732
Unallocated amounts			
Cash	**7,814**	20,942	1,985
Other	**3,806**	3,519	2,426
Total	**$111,300**	$98,412	$63,604

	1998	1997	1996
Expenditures For Segment Long-Lived Assets			
Drilling and Development	**$ 1,953**	$ 2,862	$ 1,140
Natural Gas Sales	**23,645**	10,207	8,633
Well Operations	**947**	505	364
Unallocated amounts	**85**	101	279
Total	**$ 26,630**	$13,675	$10,416

(19) QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 1998 and 1997, are as follows:

	1998				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$25,247,400	$19,161,600	$16,649,400	$21,915,200	$82,973,600
Cost of operations	21,203,300	16,328,500	15,157,200	19,169,000	71,858,000
Gross profit	4,044,100	2,833,100	1,492,200	2,746,200	11,115,600
General and administrative expenses	440,100	611,000	731,600	707,800	2,490,500
Interest expense	—	—	—	—	—
	440,100	611,000	731,600	707,800	2,490,500
Income before income taxes	3,604,000	2,222,100	760,600	2,038,400	8,625,100
Income taxes	807,300	497,700	180,400	481,700	1,967,100
Net income	$ 2,796,700	$ 1,724,400	$ 580,200	$ 1,556,700	$ 6,658,000
Basic earnings per share	$.18	$.11	$.04	$.10	$.43
Diluted earnings per share	$.17	$.11	$.03	$.10	$.41

	1997				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$23,407,800	$14,917,400	$13,955,000	$21,597,800	$73,878,000
Cost of operations	19,490,600	12,205,000	11,409,700	18,455,800	61,561,100
Gross profit	3,917,200	2,712,400	2,545,300	3,142,000	12,316,900
General and administrative expenses	498,600	592,900	631,900	595,400	2,318,800
Interest expense	102,600	101,900	83,600	27,800	315,900
	601,200	694,800	715,500	623,200	2,634,700
Income before income taxes	3,316,000	2,017,600	1,829,800	2,518,800	9,682,200
Income taxes	812,400	611,700	376,800	294,500	2,095,400
Net income	$ 2,503,600	$ 1,405,900	$ 1,453,000	$ 2,224,300	$ 7,586,800
Basic earnings per share	$.24	$.13	$.14	$.16	$.67
Diluted earnings per share	$.21	$.12	$.12	$.16	$.61

Cost of operations include cost of oil and gas well drilling operations, oil and gas purchases and production costs and depreciation, depletion and amortization.

(20) SUBSEQUENT EVENT (UNAUDITED)

On January 29, 1999, the Company offered to purchase from the Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The total of the offer if accepted by all of the approximately 6,500 investors would be approximately $13.8 million. The offer expires on March 31, 1999. Management does not expect the entire amount of the offer to be accepted by the investors. The Company plans to utilize capital received from its Public Stock Offering (see Note 5) to fund this purchase obligation.

Stock Price History and Data

The shares of Petroleum Development Corporation are traded in the National Market System of the Over-the-Counter Market under the symbol NASDAQ PETD. No dividends were paid on the common stock during the periods indicated.

At the close of 1998, the number of average common and common equivalent shares outstanding was 15,510,762 compared to 15,245,758 at the close of 1997. There is a total of 1,715 shareholders of record and approximately 2,100 shareholders whose stock is held in street name.

The following tables set forth the high and low bid prices, along with the trading volume for the periods indicated. These figures represent inter-dealer prices without retail mark-ups, mark-downs, or commissions and do not represent actual transactions.

1998	High	Low	Volume
January 1 thru March 31	$6\frac{5}{8}$	$4\frac{1}{8}$	5,043,400
April 1 thru June 30	$6\frac{1}{2}$	$4\frac{13}{16}$	5,134,000
July 1 thru September 30	$5\frac{1}{2}$	$3\frac{5}{16}$	3,324,200
October 1 thru December 31	$5\frac{3}{8}$	$2\frac{15}{16}$	3,374,800
			16,876,400

1997	High	Low	Volume
January 1 thru March 31	$5\frac{1}{8}$	$3\frac{9}{16}$	3,445,314
April 1 thru June 30	$5\frac{5}{16}$	$2\frac{7}{8}$	3,493,423
July 1 thru September 30	$11\frac{7}{16}$	$4\frac{13}{16}$	8,006,262
October 1 thru December 31	$10\frac{7}{16}$	$4\frac{3}{4}$	13,404,385
			28,349,384

Corporate Data

Directors and Officers

James N. Ryan
Chairman and Chief Executive Officer

Steven R. Williams
President and Director

Dale G. Rettinger
Executive Vice President,
Treasurer and Director

Ersel E. Morgan
Vice President Production

Thomas E. Riley
Vice President Business Development

Eric R. Stearns
Vice President Exploration
and Development

Darwin L. Stump
Controller

Roger J. Morgan
Secretary and Director

Vincent F. D'Annunzio
Director

Jeffrey C. Swoveland
Director

Auditors

KPMG LLP
Certified Public Accountants
Pittsburgh, Pennsylvania

Legal Counsel

Duane, Morris & Heckscher
Washington, District of Columbia

Young, Morgan & Cann
Clarksburg, West Virginia

Transfer Agent

OTR Stock Transfer
1130 S.W. Morris, Suite 250
Portland, Oregon 97205

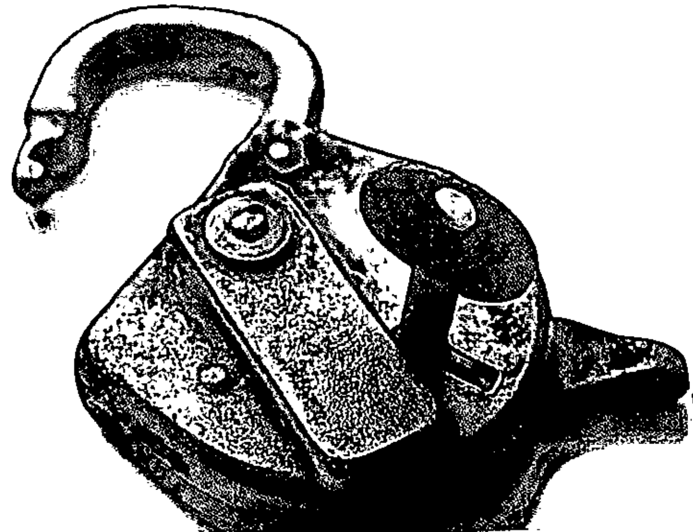
Form 10-K

A copy of the Annual Report of Petroleum Development Corporation to the Securities and Exchange Commission (Form 10-K) may be obtained by writing to the Company

Petroleum Development Corporation
P. O. Box 26
103 East Main Street
Bridgeport, West Virginia 26330

Petroleum Development Corporation

1999 Annual Report



We are Unlocking Value in Our Core Areas

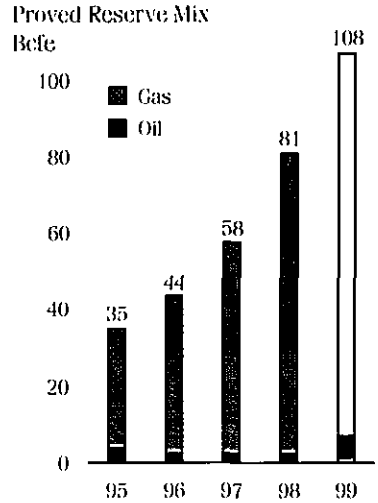
Profile

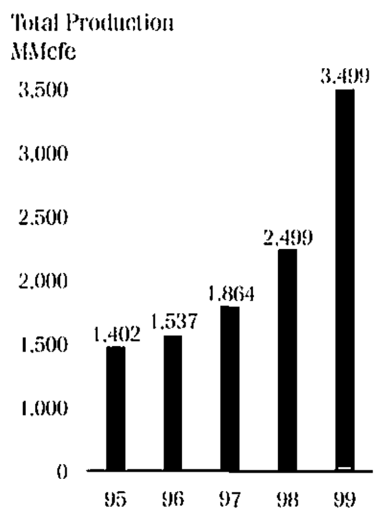
Petroleum Development Corporation (Nasdaq: PETD) (PDC) is a rapidly growing independent oil and gas producer based in Bridgeport, West Virginia. The Company has drilling and production operations in the Appalachian Basin, Michigan and the Rocky Mountains. While predominantly a natural gas producer, the Company recently added to its oil production through drilling and acquisitions in Michigan and Colorado. PDC also owns and operates a natural gas utility company in Ohio, and a West Virginia-based natural gas marketing company.

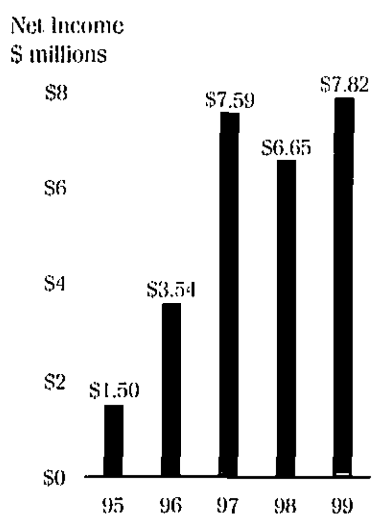
Unlocking value in its core areas through its active drilling program and strategic acquisitions is Petroleum Development's continued plan for adding shareholder value. Over the past three years, the Company has drilled 524 successful new wells, making PDC one of the top 25 operators in the U.S. For companies with a market capitalization below $100 million, PDC is the number one operator in wells drilled from 1997 through 1999. (*Oil & Gas Journal*, OGJ 200, 1997-1999) Acquisitions of producing properties totaling $15.8 million over the same three-year period, either in existing areas of operations or to expand its core competencies into new geographic basins, contributed to record reserves and production. To keep a watchful eye on expenses, PDC operates more than 2,000 wells in which it owns an interest.

Some of 1999's highlights:

- *A 10th straight profitable year, despite commodity prices.*
- Record production of 3,499 MMcfe, up from 2,499 MMcfe in 1998.
- Net income of $7.8 million, an 18% increase from 1998.
- In three transactions:
  - *Acquired a 7,500-acre Colorado lease in the Grand Valley Field of the Piceance Basin and 50 drilling sites in the Wattenberg Field in the D-J Basin.*
  - *Commenced drilling operations in Wattenberg Field and Grand Valley Field.*
  - *Acquired 53 producing wells in Wattenberg Field.*
- Increased reserves to 108 Bcfe, a 33% jump from 1998's record of 81 Bcfe.
- For the ninth time in past decade The West Virginia Department of Environmental Protection recognized PDC's commitment to our environment.







Dear Shareholders

We are pleased to report the results of another successful year and a number of new Company records, both in operations and financially. Our success is the direct result of our growth strategy, which we have strived to perfect over the years. In essence, it's a four-part plan: 1) Increase our interest in new wells drilled by PDC; 2) Acquire producing wells that meet our financial hurdles and that enhance existing operations or help us establish an operation in a new drilling area; 3) Expand our operations into new geographic areas with superior development opportunities and where our operating expertise can be effectively leveraged; and 4) Mitigate our exposure to commodity price volatility by using financial hedges or term contracts.

By consistently following this strategy for several years, we continue to unlock value in our core areas. Our corporate strengths are the keys to this success. PDC is fortunate to have loyal, talented and experienced employees, a strong financial position, our successful partnership operations, and an appreciation and respect of what we know, and don't know, about oil and gas operations.

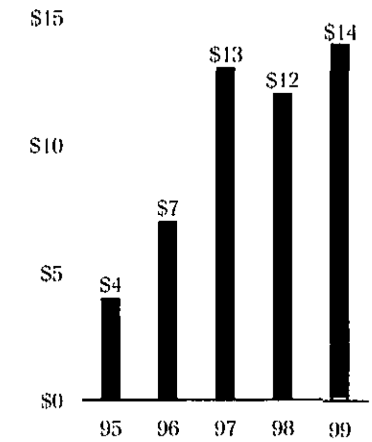
Two of 1999's most significant developments were a dramatic increase in our production and the commencement of operations in the Rocky Mountain region. The Rockies are an example of respecting our knowledge about oil and gas. Geographic expansion of our core operating area was a natural for PDC. Our geologists and engineers are very comfortable with their ability to apply their previous experience to our new Colorado projects. The geology is similar, production life is predictable and dry holes are an anomaly. In fact, we've been contracting some of the very same rigs that once drilled for us in the Appalachian Basin.

Our newer areas, Michigan and the Rocky Mountains, were responsible for nearly half of our production in December 1999. We expect their contribution to 2000 full-year numbers to be even greater as PDC continues to acquire and exploit in the Rockies and brings on additional production in Michigan.

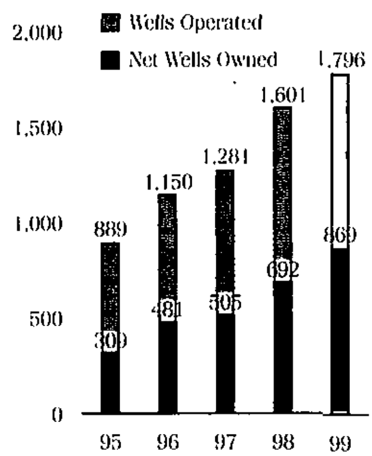
Most of our Rocky Mountain production in 1999 resulted from a December acquisition of 53 wells in the Wattenberg Field in the Denver-Julesburg (D-J) Basin. We began drilling new Wattenberg wells during the fourth quarter, adding four successful new wells by the end of the year. On Colorado's Western Slope we completed our first Piceance Basin well, which was spudded in January 2000. Developmental drilling is the focus in both of these areas; with new wells directly offsetting existing producing wells. In addition to being a good match for our technical capabilities, the Rockies are the only onshore growth area in the United States. In fact, total Colorado gas production has nearly doubled since 1993, while overall U.S. production increased by only 3 percent.

Not all of our operations were successful. We drilled two exploratory wells in Moffat County, Colo., which failed to find anticipated reserves, and two in Montana with similar results. Each of the projects had the potential to open significant new areas for development. Exploratory wells are generally more risky than development wells, but to secure future opportunities, such risks are a necessary part of being an exploration and production company. We continue to seek certain exploratory projects with substantial upside potential.

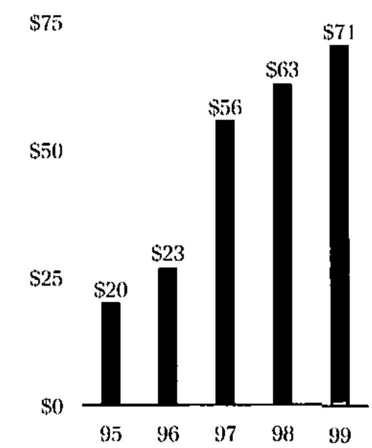
EBITDA
$ millions



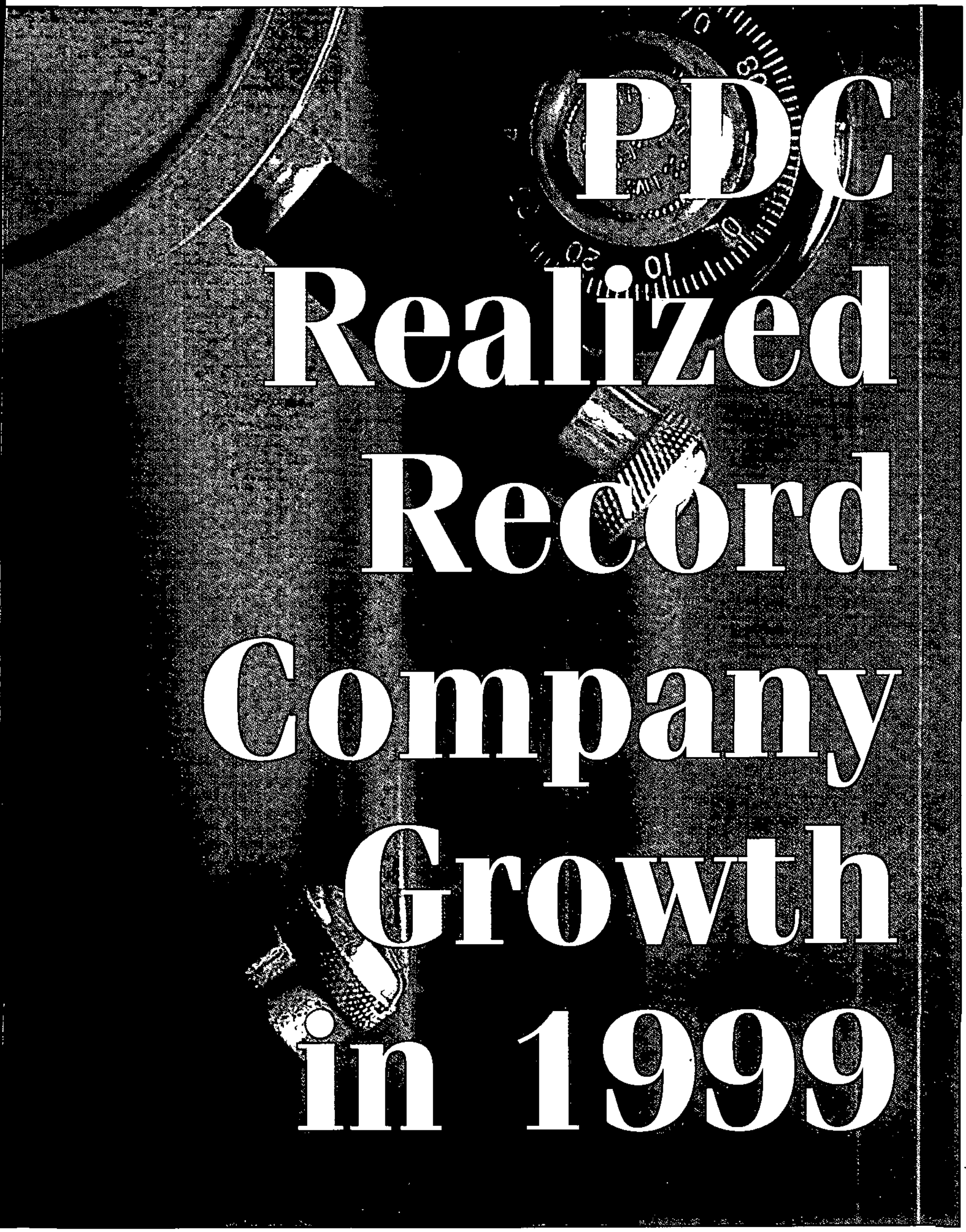
Net Wells Owned / Wells Operated



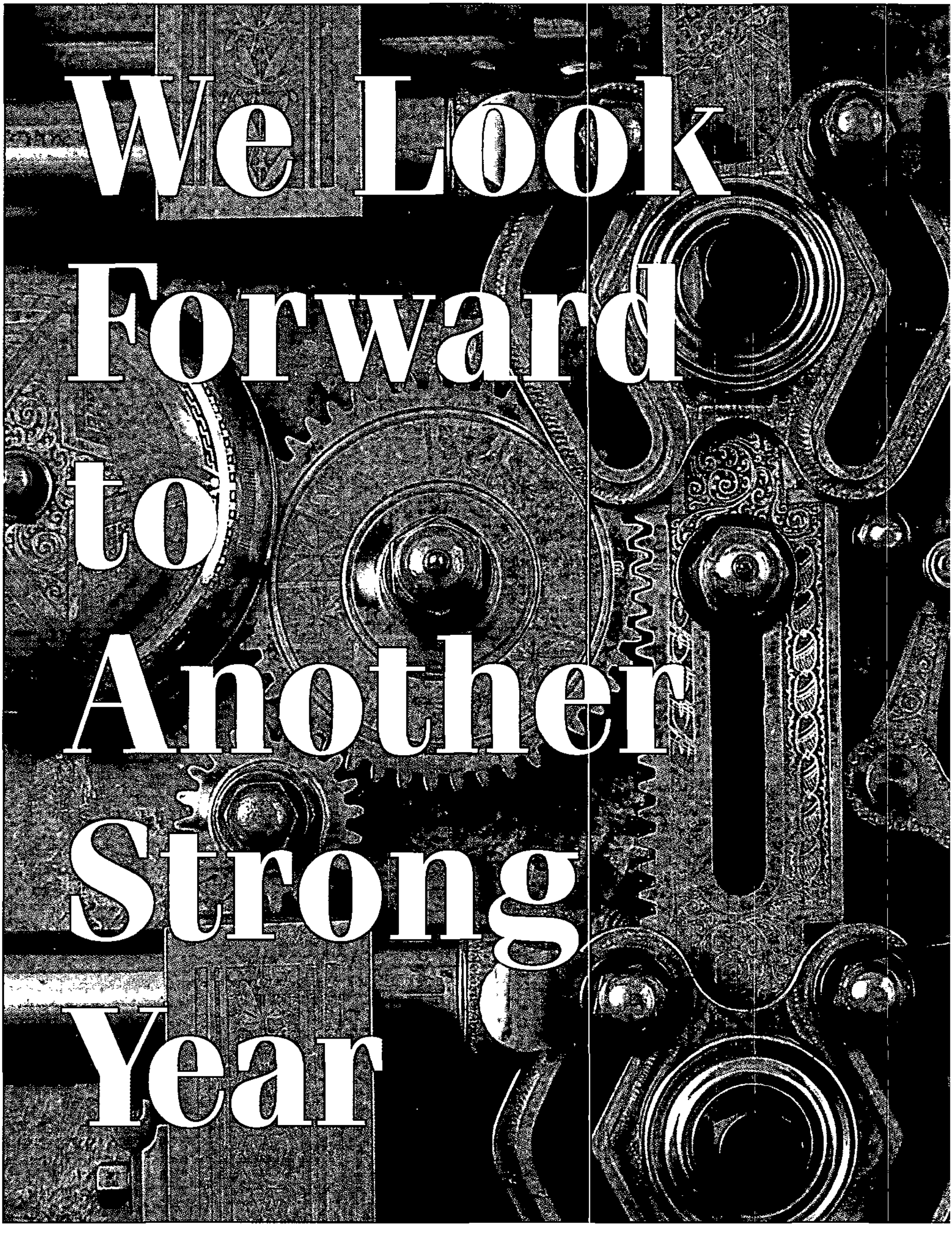
Total Shareholders' Equity
$ millions



PDC Realized Record Company Growth in 1999



We Look Forward to Another Strong Year



Unfavorable commodity prices took some of the luster off our operational success, with 1999 gas prices unchanged from historically low 1998 levels. So far, 2000 looks like a much stronger year for oil and gas prices. The low gas prices of the past two years have reduced drilling capital expenditures across the industry, and U.S. reserves and productive capacity simply haven't been replaced. Also, the 1999-2000 winter heating season experienced cooler weather patterns compared to the prior two years, directly increasing natural gas demand. This supply / demand situation should continue to support higher gas prices as the year progresses and we move into the summer cooling season.

Our plans for 2000 include an increasing shift of operations westward. We have been extremely pleased with our Colorado results to date and intend to allocate about half of our drilling program expenditures to the Rockies region. We expect to gradually reduce development activities in both the Michigan and Appalachian Basins. Our geologists continue to identify additional Rocky Mountain opportunities which match our economic, risk, and operational parameters to be added to our drilling options in the coming year.

Our current capital budget for 2000 is $22 million. Approximately two-thirds of the total is earmarked for drilling activities, with the remaining third going for acquisition of producing properties. We expect operating cash flow to cover about two-thirds of the budget with the other third provided by borrowing from the unused portion of our bank credit line.

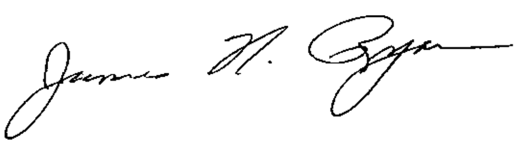
PDC continues to look for attractive acquisition opportunities. By adhering to our four-point plan, we are able to eliminate the ill-fitting potential acquisitions and concentrate on the ones that make the most sense for PDC. Leveraging our knowledge and operational strength at all times is the most sound way to ensure meaningful corporate growth and enhanced shareholder value.

Our drilling partnerships continue to be well received by the market, although sales were off about 10 percent in 1999 compared to 1998 because of weather-related low natural gas prices. With the strengthening market and stronger results from our diversified drilling portfolio, we look forward to another strong year of partnership sales.

Unlike prior years when our oil production was negligible, PDC is now benefiting from oil price increases. Our wells in Colorado's Wattenberg Field produce oil as well as natural gas, and we are developing a small oil field in Michigan with possible reserves of 500,000 barrels. PDC owns an 80 percent working interest in the development. Sustained higher oil prices will benefit both projects.

Finally, we are quite pleased to announce that for the ninth time in the last decade, PDC has been recognized for the quality of its environmental efforts. The West Virginia Department of Environmental Protection acknowledged us for strict attention to maintaining the environment in our drilling and completion activities. We are grateful for the recognition and proud of the employees who make it possible year after year.

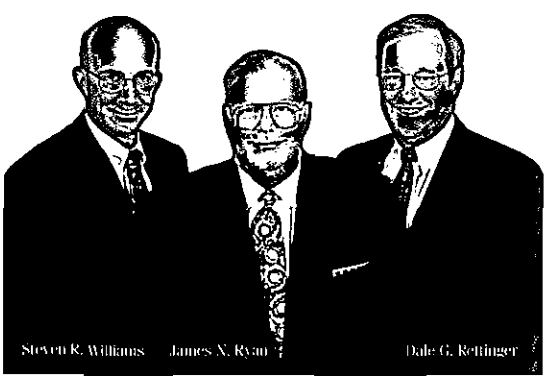
Our business plan is working, and with the addition of the Rocky Mountain properties and continued robust commodity prices, our strategy going forward should result in another record year for Petroleum Development Corporation.



James N. Ryan, Chairman and CEO

Steven R. Williams, President

Dale G. Rettinger, Executive Vice President



Steven R. Williams James N. Ryan Dale G. Rettinger

Operations

In our 30-year history, we have always leveraged our employees' expertise when moving into new core operating areas. Extending our Appalachian roots, PDC began Michigan operations in 1997 and commenced successful developmental and exploratory drilling in Colorado in 1999. These three core areas include 205,000 acres, over 2,000 producing wells and hundreds of potential drilling locations to help PDC continue growing.

Appalachian Basin

Petroleum Development Corporation originated as an Appalachian producer, and our holdings in the area still generate the majority of our production revenue. Most West Virginia properties are located in the north central part of the state in close proximity to the Bridgeport headquarters. A second concentration of Appalachian wells is located in the west-central part of Pennsylvania, with a field office located Mahaffey, Pa. Most of the Company's Pennsylvania wells have been drilled or acquired since 1995.

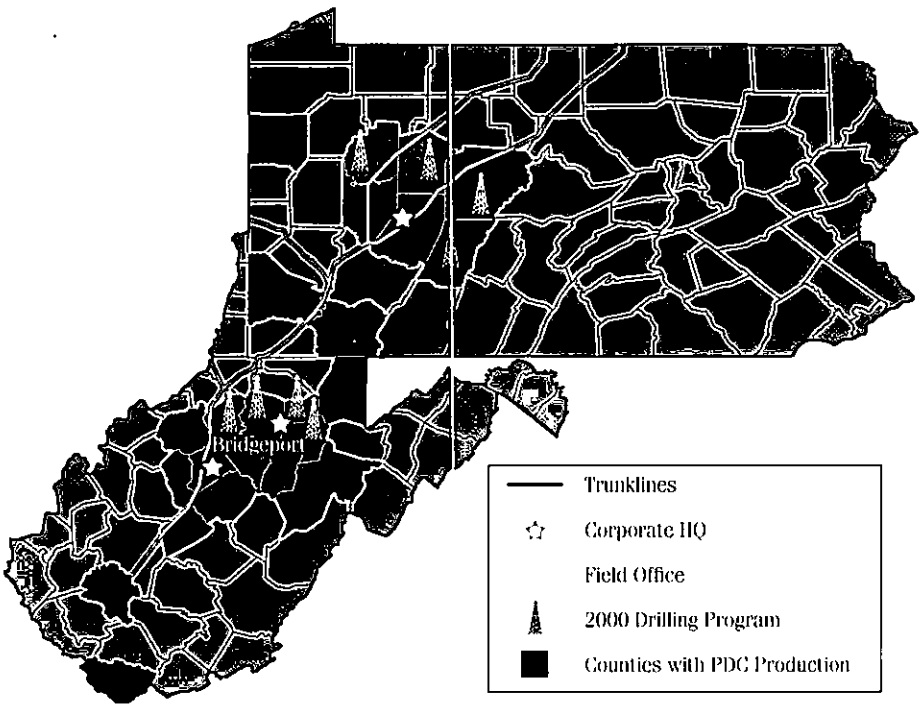
At the end of 1999 the Company operated 1,538 wells in the Appalachian region. PDC's production in the region was 2.5 Bcfe during 1999, for an average rate of 6,852 Mcfe per day. The average daily production rate in December 1999 was 7,088 Mcfe, up from 6,394 Mcfe per day in December 1998, an 11 percent increase. During 1999, the Company drilled 99 successful new wells in the Appalachian region, with only eight dry holes. Exiting 1999, a total of 14 wells were not yet in production.

During 2000, the Company plans to drill approximately 40 wells in the Appalachian region, retaining a 20 percent working interest (eight net wells). Our leasehold position includes 80,100 acres, with over 100 development locations. Year 2000 spending here represents about 20 percent of total capital outlays.

Primary Appalachian region targets for new wells are Devonian- and Mississippian- aged sandstones and fractured Devonian shales. While these targets seldom have high initial production rates, they are widespread and predictable. Historically, the Company has completed over 92 percent of the wells it has drilled. Productive lives of 25 to 30 years or more are common. As a result, the wells make an excellent production base, since the annual production rate decline is relatively small and can be accurately forecast.

In the past, Appalachian natural gas production has sold at a premium to gas produced in most other areas because of its proximity to major national gas markets. The warm winters of the past couple years have reduced the premium substantially. However, a return to more normal winter conditions is likely to result in an increase in the price advantage from current levels.

In addition to its production operations, PDC has two subsidiaries involved in the wholesale and retail sale of natural gas in the region. Paramount Natural Gas is an Ohio natural gas utility distributing natural gas to residential and commercial end-users in the central part of the state. In 1999, it posted sales of about $2.0 million. Riley Natural Gas (RNG) is a natural gas marketing company operating out of our Bridgeport headquarters. RNG also manages PDC's gas marketing in Michigan and the Rockies.

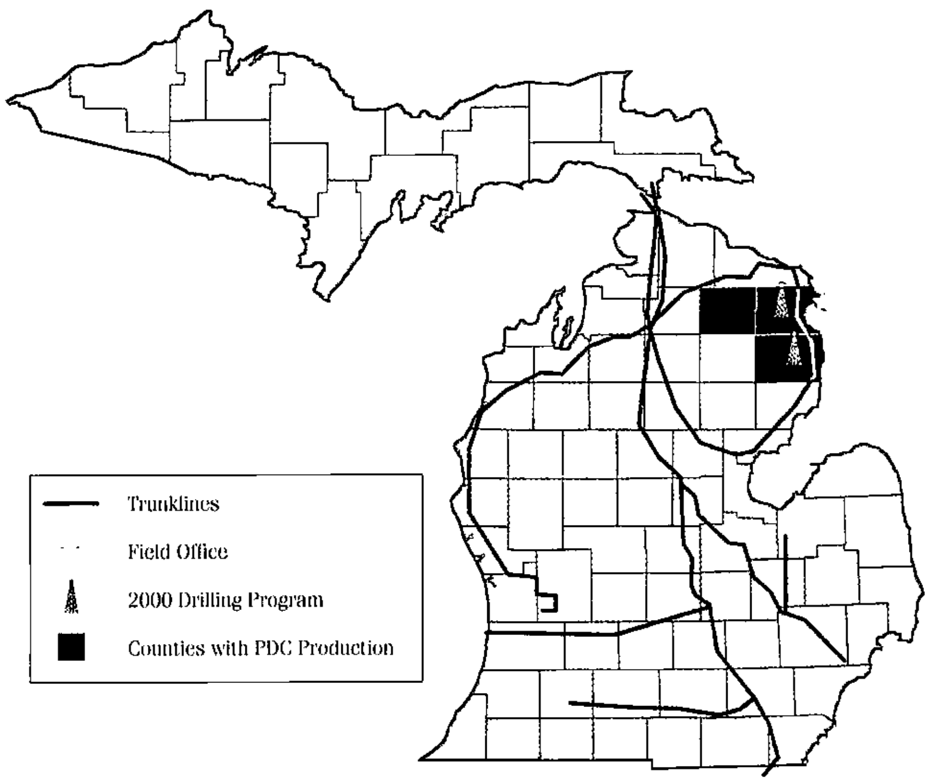


RNG aggregates supplies from over 100 Appalachian producers and sells it to end-users and other gas marketers. RNG sales totaled approximately $36.6 million in 1999.

Michigan Basin

Petroleum Development began its Michigan drilling operations in 1997. In 1998, a 13-well producing field was acquired to help establish an operations base. Six production employees staff the Company's Michigan field office in Ossineke. Geological and engineering activities are managed from our Bridgeport office.

At year-end 1999, PDC had 188 producing wells in Michigan with another 12 wells drilled but not yet in production. The Company produced 1.0 Bcfe during 1999 with an average daily production rate of 2,632 Mcfe. The December 1999 average daily production rate was 4,950 Mcfe, up from 1,105 Mcfe per day in December 1998, an increase of 348 percent. Michigan production rates are expected to continue rising as wells already drilled but not yet in production are connected for sales, and as the dewatering process of producing wells continues. Production rates on Antrim shale wells like those operated by PDC typically continue to increase for six to 18 months as the water initially filling the reservoir is produced and gas finds a direct path to the wellbore.



During 1999, 62 new wells were drilled in Michigan with 61 successful and one dry hole. Included in the total is one successful exploratory well drilled to test the Richfield formation, an oil-producing zone at a depth of 4,300 feet. A 30-day test of the Richfield well indicated an initial productive capacity of approximately 40 barrels per day. There may be as many as 10 offset development locations on the Company's current acreage position with possible gross reserves of 500,000 barrels. PDC retains an 80 percent working interest in wells on the lease.

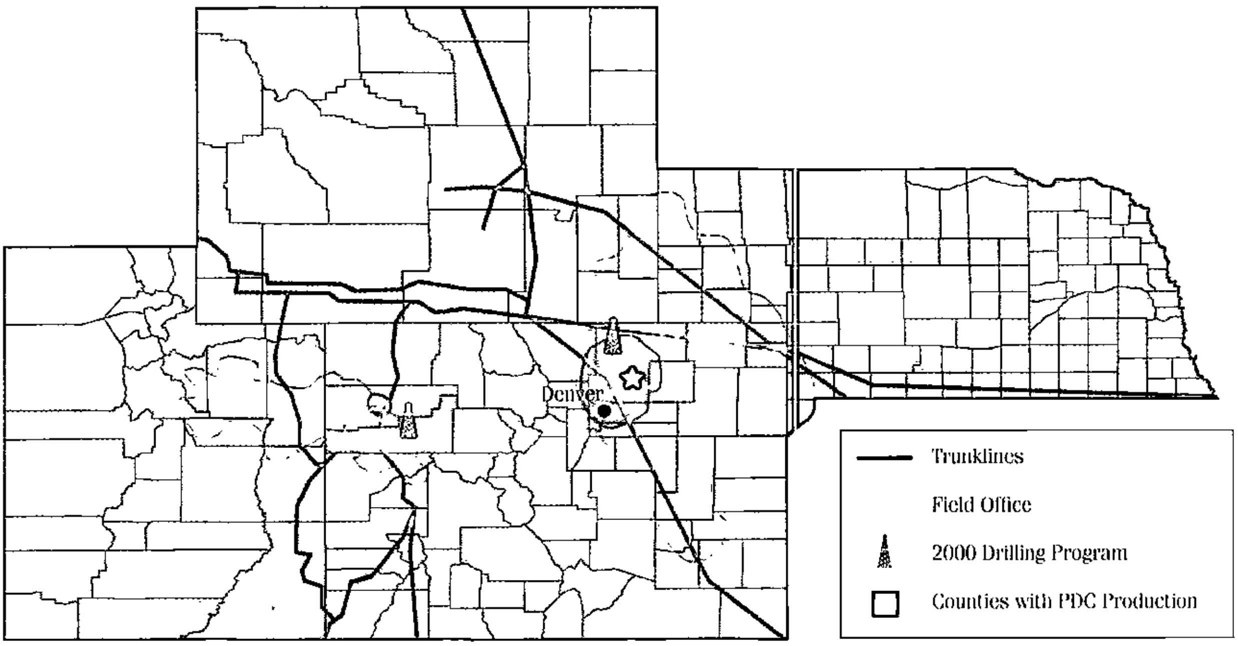
Our primary target for new Michigan wells is the Antrim shale. In productive areas the shale is generally located at depths of approximately 1,000 feet. Economic gas reserves are found in areas of fractured shale that is initially water-filled. Dewatering is necessary before gas production can begin from fractured shales. After dewatering is complete, production peaks and the wells begin a long, gradual decline. As with Appalachian Basin wells, Michigan wells are expected to have long productive lives exceeding 20 years.

Rocky Mountain Region

In 1999, Petroleum Development added the Rocky Mountains to its core operating areas. The similarities to Appalachian Basin geology, coupled with the access to prime acreage, provided the impetus for our geographic expansion. After arriving, we participated in two exploratory projects, began development drilling into two other areas and opened a new field office in Fort Lupton, approximately 25 miles north of Denver. Soon after, we relocated a supervisor with previous Rocky Mountain experience from the Appalachian region. In early December PDC acquired 100 percent of the working interest in 53 Wattenberg Field wells. Also in December, we acquired the rights to develop a 7,500-acre lease in the Piceance Basin as well as the rights to 20 development locations in Wattenberg Field.

Exiting 1999, PDC had 58 producing wells in the Rocky Mountain region, all in the Wattenberg Field. During 1999, the Company drilled four exploratory wells, two in Colorado and two in Montana, none of which found sufficient reserves to justify further development. In addition, we drilled four development wells in the Wattenberg Field, all of which were successful. At year-end, two of those wells were in production, and two were awaiting completion, surface equipment, and pipeline connections.

Total production for the Rocky Mountain region in 1999 was 57 MMcfe, all of which was produced in November and December. Wattenberg Field wells produce significant amounts of oil in conjunction with their gas production. Average daily production in December 1999 was 1,918 Mcfe.

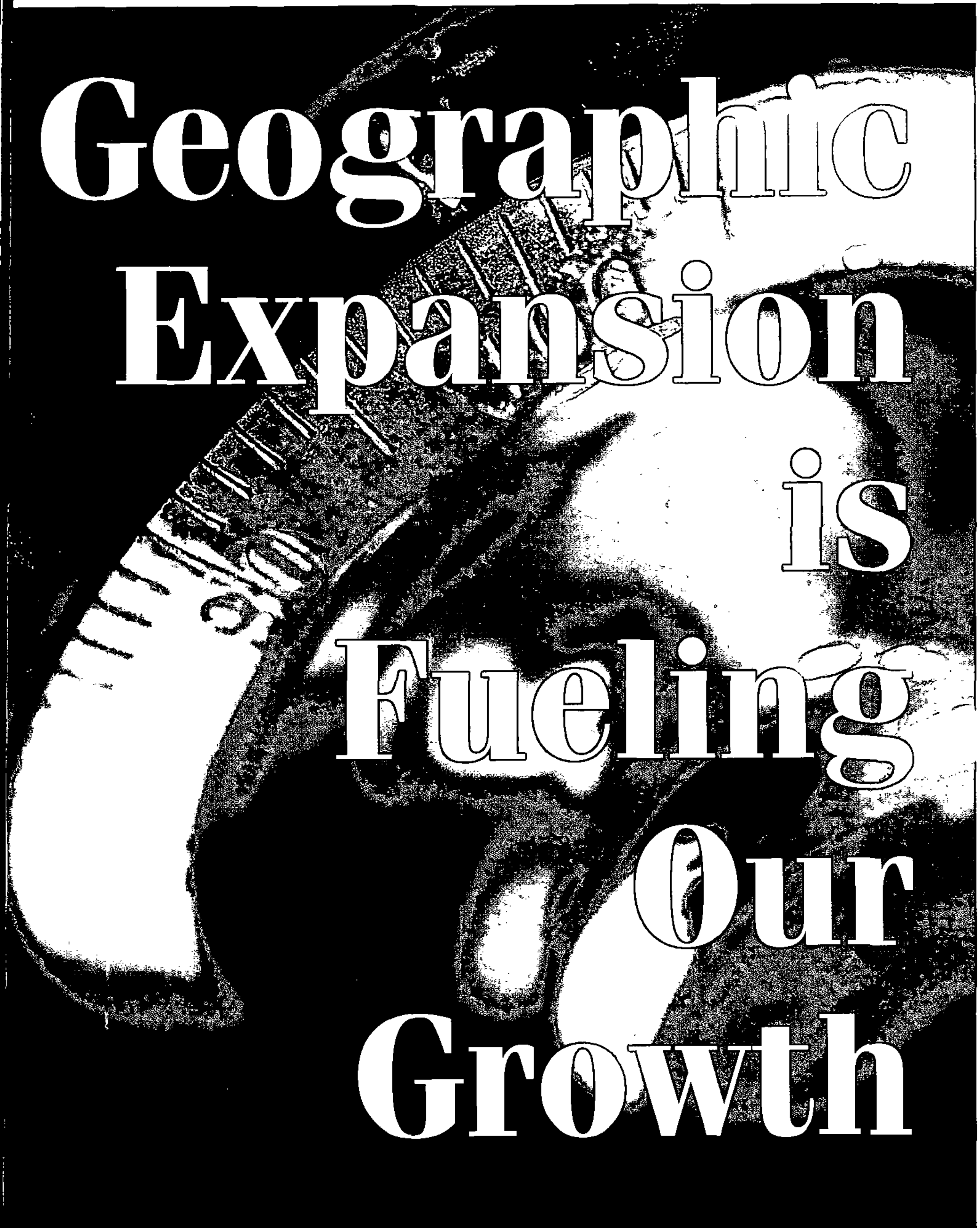


Petroleum Development will continue developing the Wattenberg Field locations and its Piceance Basin lease during 2000. Wattenberg Field wells are drilled to depths ranging from approximately 6,500 feet to 8,000 feet and feature four or more zones that are potentially productive in each well, but the primary target is the Codell formation. Other zones are the Sussex, Niobrara, and J Sand. The wells are predominantly natural gas producers, but 10 percent or more of the value may be associated with oil production.

PDC's Piceance Basin acreage is located in the Grand Valley field northeast of Grand Junction, Colo. Well depths may range from approximately 6,000 feet to 10,000 feet depending upon the surface elevation. The productive formation is the Mesaverde, an interval of stacked sandstones, shales, and coal ranging up to about 3,000 feet in thickness. Historically, dry hole rates in the field have been very low.

Our team of geologists is investigating extensions to existing lease positions and additional development opportunities in the Rocky Mountain region. We will also continue to seek complementary acquisition opportunities in the area.

Geographic Expansion is Fueling Our Growth



Ten-Year Selected Financial Data

in thousands, except per share amounts

Income Statement		1990		1991		1992		1993
Revenues								
Oil and Gas Well Drilling Operations	$	9,417	$	11,070	$	14,931	$	12,073
Oil and Gas Sales	$	3,757	$	3,567	$	4,867	$	4,471
Well Operations Income	$	2,290	$	2,694	$	2,936	$	3,843
Other Income	$	271	$	507	$	433	$	98
Total Revenues	$	15,735	$	17,839	$	23,166	$	20,485
Total Costs and Expenses	$	15,078	$	16,493	$	20,552	$	18,890
Costs and Expenses (Excluding Interest and Depreciation, Depletion, and Amortization)	$	12,751	$	14,931	$	18,826	$	17,116
Interest Expense	$	1,020	$	56	$	54	$	55
Depreciation, Depletion and Amortization	$	1,307	$	1,505	$	1,672	$	1,717
Income Before Extraordinary Items	$	384	$	870	$	1,748	$	1,321
Extraordinary Item Net of Income Taxes	$	1,928	$	-	$	-	$	269
Reported Net Income	$	2,312	$	870	$	1,748	$	1,590
Per Share								
Net income	$	0.23	$	0.07	$	0.14	$	0.14
Fully Diluted Net Income	$	0.18	$	0.08	$	0.16	$	0.14
Cash Flow	$	0.36	$	0.20	$	0.31	$	0.30
EBITDA	$	0.45	$	0.22	$	0.34	$	0.32
Weighted Average Common Shares Outstanding (Diluted)		13,741		13,470		12,633		11,564
Balance Sheet								
Total Current Assets	$	9,574	$	10,187	$	12,092	$	13,506
Property and Equipment	$	34,204	$	35,896	$	37,931	$	39,829
Less Accumulated Depreciation, Depletion, and Amortization	$	13,551	$	14,819	$	22,365	$	21,914
Net Property and Equipment	$	20,653	$	21,077	$	15,566	$	17,915
Total Assets	$	31,219	$	32,040	$	34,631	$	36,413
Working Capital	$	(865)	$	(997)	$	(590)	$	289
Long-term Debt, excluding current maturities	$	4,634	$	3,354	$	3,969	$	3,167
Total Shareholders' Equity	$	12,310	$	13,264	$	15,347	$	17,236
Net Income	$	2,312	$	870	$	1,748	$	1,590
Deferred Taxes	$	1,370	$	325	$	508	$	166
DD&A	$	1,306	$	1,505	$	1,672	$	1,717
Cash Flow	$	4,988	$	2,700	$	3,928	$	3,473
Interest	$	1,020	$	56	$	54	$	55
Income Taxes	$	1,569	$	476	$	866	$	365
EBITDA	$	6,207	$	2,908	$	4,340	$	3,727
Production Costs	$	558	$	511	$	501	$	581

1994	1995	1996	1997	1998	1999
$ 15,190	$ 13,941	$ 18,698	$ 34,405	$ 40,447	$ 42,116
$ 4,361	$ 4,151	$ 26,051	$ 33,390	$ 35,560	$ 46,988
$ 3,730	$ 3,751	$ 3,929	$ 4,509	$ 4,581	$ 5,314
$ 524	$ 504	$ 936	$ 1,573	$ 2,385	$ 2,392
$ 23,806	$ 22,346	$ 49,614	$ 73,878	$ 82,974	$ 96,811
$ 22,708	$ 20,514	$ 44,964	$ 64,196	$ 74,348	$ 86,710
$ 20,559	$ 18,042	$ 42,274	$ 61,220	$ 71,095	$ 82,679
$ 300	$ 320	$ 380	$ 316	$ 0	$ 182
$ 1,848	$ 2,152	$ 2,310	$ 2,660	$ 3,254	$ 4,031
$ 922	$ 1,481	$ 3,549	$ 7,587	$ 6,658	$ 7,824
$ -	$ -	$ -	$ -	$ -	$ -
$ 922	$ 1,481	$ 3,549	$ 7,587	$ 6,658	$ 7,824
$ 0.08	$ 0.13	$ 0.34	$ 0.67	$ 0.43	$ 0.50
$ 0.08	$ 0.13	$ 0.31	$ 0.61	$ 0.41	$ 0.48
$ 0.24	$ 0.32	$ 0.53	$ 0.83	$ 0.62	$ 0.73
$ 0.27	$ 0.37	$ 0.64	$ 1.01	$ 0.73	$ 0.88
11,990	11,611	11,542	12,540	16,338	16,287
$ 12,123	$ 13,157	$ 28,619	$ 53,859	$ 44,009	$ 42,260
$ 44,960	$ 48,240	$ 56,962	$ 67,792	$ 92,747	$ 118,349
$ 19,204	$ 21,127	$ 22,522	$ 24,223	$ 27,357	$ 31,207
$ 25,756	$ 27,113	$ 34,440	$ 43,569	$ 65,390	$ 87,142
$ 38,325	$ 40,620	$ 63,604	$ 98,412	$ 111,300	$ 132,084
$ (1,614)	$ (1,520)	$ (2,357)	$ 16,483	$ 1,525	$ (2,504)
$ 3,100	$ 2,500	$ 5,320	$ 0	$ 0	$ 9,300
$ 18,380	$ 19,921	$ 23,072	$ 55,766	$ 62,747	$ 70,725
$ 922	$ 1,481	$ 3,549	$ 7,587	$ 6,658	$ 7,824
$ 97	$ 113	$ 214	$ 108	$ 244	$ 109
$ 1,848	$ 2,152	$ 2,310	$ 2,660	$ 3,254	$ 4,031
$ 2,867	$ 3,746	$ 6,073	$ 10,355	$ 10,156	$ 11,964
$ 300	$ 320	$ 380	$ 316	$ 0	$ 182
$ 177	$ 351	$ 1,101	$ 2,095	$ 1,967	$ 2,276
$ 3,247	$ 4,304	$ 7,340	$ 12,658	$ 11,879	$ 14,314
$ 735	$ 596	$ 964	$ 1,206	$ 1,517	$ 2,422

Ten-Year Selected Operating Data

Estimated Oil and Gas Reserves	1990	1991	1992	1993
Proved Developed Reserves				
Natural Gas (MMcf)	17,942	18,938	20,477	20,181
Oil (MBbl)	128	84	78	91
Total (MMcfe)	18,710	19,442	20,945	20,727
Total Reserves				
Natural Gas (MMcf)	22,454	23,432	24,980	24,660
Oil (MBbl)	128	84	78	91
Total (MMcfe)	23,222	23,936	25,448	25,206
SEC PV-10 After Tax (000)	$ 15,682	$ 13,028	$ 15,515	$ 14,018
Oil and Gas Operations				
Production				
Natural Gas (MMcf)	682	867	948	965
Oil (MBbl)	16	12	16	10
Total (MMcfe)	778	939	1044	1025
Average Sales Price				
Natural Gas (per Mcf)	$ 2.50	$ 2.16	$ 2.41	$ 2.24
Oil (per MBbl)	$ 22.17	$ 17.52	$ 18.21	$ 16.62
Natural Gas Equivalents (per Mcfe)	$ 2.65	$ 2.22	$ 2.47	$ 2.27
Lease Operating Expenses and Production Taxes (per Mcfe)	$ 0.72	$ 0.54	$ 0.48	$ 0.57
EBITDA (per Mcfe)	$ 7.98	$ 3.10	$ 4.16	$ 3.64
Operating Margin Percentage (EBITDA/Operating Revenues)	39%	16%	19%	18%
Depreciation, Depletion and Amortization Costs (per Mcfe)	$ 1.68	$ 1.60	$ 1.60	$ 1.68
Wells Operated	714	707	699	725
Net Wells Owned	214	217	224	226
Average Ownership in Operated Wells	30%	31%	32%	31%
Drilling				
Gross Wells				
Exploratory	2	0	0	3
Development	55	53	80	56
Dry Hole	8	4	7	10
Success Rate	86%	92%	91%	83%
Production Replacement, All Sources (%)	240%	176%	245%	76%

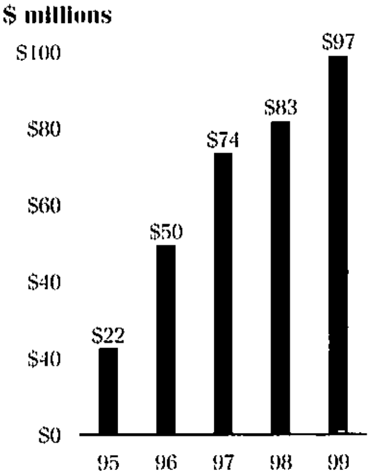
1994	1995	1996	1997	1998	1999
27,746	29,326	35,516	42,411	64,562	82,628
79	140	81	45	29	798
28,220	30,166	36,002	42,681	64,736	87,416
32,225	33,829	43,312	57,243	80,819	101,245
79	140	81	45	29	1154
32,699	34,669	43,798	57,513	80,993	108,169
$ 14,445	$ 21,060	$ 34,262	$ 27,936	$ 30,194	$ 58,454
1,195	1,336	1,495	1,810	2,453	3,451
11	11	7	9	8	8
1,261	1,402	1,537	1,864	2,501	3,499
$ 2.01	$ 1.75	$ 3.04	$ 2.88	$ 2.46	$ 2.46
$ 14.41	$ 15.80	$ 16.35	$ 16.10	$ 10.61	$ 18.75
$ 2.03	$ 1.79	$ 3.03	$ 2.87	$ 2.45	$ 2.47
$ 0.58	$ 0.58	$ 0.63	$ 0.65	$ 0.61	$ 0.69
$ 2.57	$ 3.07	$ 4.78	$ 6.79	$ 4.75	$ 4.09
14%	19%	15%	17%	14%	15%
$ 1.47	$ 1.54	$ 1.50	$ 1.43	$ 1.30	$ 1.15
829	889	1150	1281	1601	1796
298	309	481	505	692	869
36%	35%	42%	39%	43%	48%
0	0	0	0	1	5
75	72	97	168	212	173
4	8	5	10	12	13
95%	89%	95%	94%	94%	93%
694%	241%	694%	836%	1039%	877%

Management's Discussion and Analysis of Financial Condition and Results of Operations

Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995

Statements, other than historical facts, contained in this Annual Report, including statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and Management's strategies, plans and objectives, are "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Although the Company believes that its forward looking statements are based on reasonable assumptions, it cautions that such statements are subject to a wide range of risks and uncertainties incident to the exploration for, acquisition, development and marketing of oil and gas, and it can give no assurance that its estimates and expectations will be realized. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to, changes in production volumes, worldwide demand, and commodity prices for petroleum natural resources; the timing and extent of the Company's success in discovering, acquiring, developing and producing oil and gas reserves; risks incident to the drilling and operation of oil and gas wells; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; the effect of hedging activities; and conditions in the capital markets. Other risk factors are discussed elsewhere in this Form 10-K.

Total Revenue
$ millions



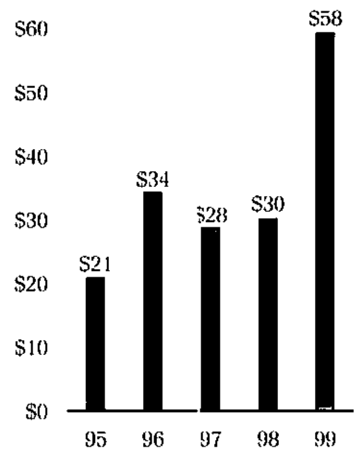
Results of Operations
Year Ended December 31, 1999 Compared with December 31, 1998

Revenues

Total revenues for the year ended December 31, 1999 were $96.8 million compared to $83.0 million for the year ended December 31, 1998, an increase of approximately $13.8 million, or 16.6%. Drilling revenues for the year ended December 31, 1999 were $42.1 million compared to $40.4 for the year ended December 31, 1998, an increase of approximately $1.7 million, or 4.2%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1999 were $47.0 million compared to $35.6 million for the year ended December 31, 1998, an increase of approximately $11.4 million, or 32.0%. Such increase was due to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. The increase in production from the Company's producing properties from 1998 to 1999 was 40.7%. Well operations and pipeline income for the year ended December 31, 1999 was $5.3 million compared to $4.6 million for the year ended December 31, 1998, an increase of approximately $700,000 or 15.2%. Such increase resulted from an increase in the number of wells operated by the Company. Other income remained constant at $2.4 million for the years ended December 31, 1999 and 1998. However for the year ended December 31, 1999 a gain on the sale of oil and gas property offset the decrease in interest earned in 1999 compared to 1998 due to lower average cash balances.

Costs and Expenses

SEC PV-10 (after tax)
$ millions



Costs and expenses for the year ended December 31, 1999 were $86.7 million compared to $74.3 million for the year ended December 31, 1998, an increase of approximately $12.4 million, or 16.7%. Oil and gas well drilling operations costs for the year ended December 31, 1999 were $35.5 million compared to $35.0 million for the year ended December 31, 1998, an increase of approximately $500,000 or 1.4%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1999 were $44.2 million compared to $33.6 million for the year ended December 31, 1998, an increase of approximately $10.6 million, or 31.5%. Such increase was due primarily to natural gas marketing activities of RNG along with production costs associated with the increased production from the Company's producing properties. General and administrative expenses for the year ended December 31, 1999 were $2.8 million compared to $2.5 million for the year ended December 31, 1998, an increase of approximately $300,000. Depreciation, depletion and amortization costs for the year ended December 31, 1999 were $4.0 million compared to $3.3 million for the year ended December 31, 1998, an increase of approximately $700,000 or 21.2%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs were $182,000 for the year ended December 31, 1999 as the Company utilized its credit agreement during the third and fourth quarters of 1999.

Net Income

Net income for the year ended December 31, 1999 was $7.8 million compared to $6.7 million for the year ended December 31, 1998, an increase of approximately $1.1 million or 16.4%.

Year Ended December 31, 1998 Compared with December 31, 1997

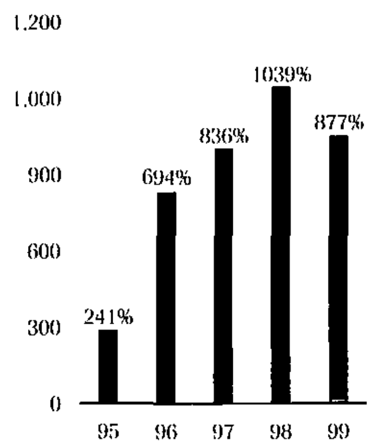
Revenues

Total revenues for the year ended December 31, 1998 were $83.0 million compared to $73.9 million for the year ended December 31, 1997, an increase of approximately $9.1 million, or 12.3%. Drilling revenues for the year ended December 31, 1998 were $40.4 million compared to $34.4 for the year ended December 31, 1997, an increase of approximately $6.0 million, or 17.4%. Such increase was due to an increase in drilling and completion activities, which was a direct result of an increase in drilling funds from the Company's public drilling programs. Oil and gas sales for the year ended December 31, 1998 were $35.6 million compared to $33.4 million for the year ended December 31, 1997, an increase of approximately $2.2 million, or 6.6%. Such increase was due primarily to the natural gas marketing activities of RNG, along with increased production from the Company's producing properties. This increase in production was offset in part by lower average sales prices from the Company's producing properties and decreased natural gas purchased for resale. Well operations and pipeline income for the year ended December 31, 1998 was $4.6 million compared to $4.5 million for the year ended December 31, 1997, an increase of approximately $100,000, or 2.2%. Such increase resulted from an increase in the number of wells operated by the Company. Other income for the year ended December 31, 1998 was $2.4 million compared to $1.6 million for the year ended December 31, 1997, an increase of approximately $800,000 or 50.0%. Such increase was due to management fees earned on higher volumes of drilling partnerships and interest earned on higher average cash balances.

Costs and Expenses.

Costs and expenses for the year ended December 31, 1998 were $74.3 million compared to $64.2 million for the year ended December 31, 1997, an increase of approximately $10.1 million, or 15.7%. Oil and gas well drilling operations costs for the year ended December 31, 1998 were $35.0 million compared to $28.0 million for the year ended December 31, 1997, an increase of approximately $7.0 million, or 25.0%. Such increase resulted from additional expenses due to increased drilling activity. Oil and gas purchases and production costs for the year ended December 31, 1998 were $33.6 million compared to $30.9 million for the year ended December 31, 1997, an increase of approximately $2.7 million, or 8.7%. Such increase was due primarily to natural gas marketing activities of RNG along with production costs associated with the increased production from the Company's producing properties, offset in part by lower volumes of gas purchased for resale by the Company. General and administrative expenses for the year ended December 31, 1998 were $2.5 million compared to $2.3 million for the year ended December 31, 1997, an increase of approximately $200,000. Depreciation, depletion and amortization costs for the year ended December 31, 1998 were $3.3 million compared to $2.7 million for the year ended December 31, 1997, an increase of approximately $600,000 or 18.5%. Such increase was due to the increased amount of investment in oil and gas properties owned by the Company. Interest costs were eliminated after the Company extinguished the balance on its bank credit line in November, 1997.

Production Replacement All Sources



Net Income

Net income for the year ended December 31, 1998 was $6.7 million compared to $7.6 million for the year ended December 31, 1997, a decrease of approximately $900,000, or 11.8%.

Year 2000 Issue

The Company experienced no known disruptions as a result of the year date change and intends to continue monitoring its critical systems at various other date changes during the Year 2000.

DD&A Costs per Mcfe

The Company expenditures for addressing Year 2000 issues were not material, nor does the Company expect to incur any significant costs addressing Year 2000 issues in the future.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations, capital raised through stock offerings and drilling partnerships, and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas from the Company's well interests, well drilling and operating activities for the Company's investor partners, natural gas gathering and transportation, and natural gas marketing. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with operating cash flow accruing to the Company to the extent payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Sales volumes of natural gas have continued to increase while natural gas prices fluctuate monthly. The Company's natural gas sales prices are subject to increase and decrease based on various market-sensitive indices. A major factor in the variability of these indices is the seasonal variation of demand for the natural gas, which typically peaks during the winter months. The volumes of natural gas sales are expected to continue to increase as a result of continued drilling activities and additional investment by the Company in oil and gas properties. The Company utilizes commodity-based derivative instruments (natural gas futures and option contracts traded on the NYMEX) as hedges to manage a portion of its exposure to this price volatility. The futures contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a three to twelve-month period.

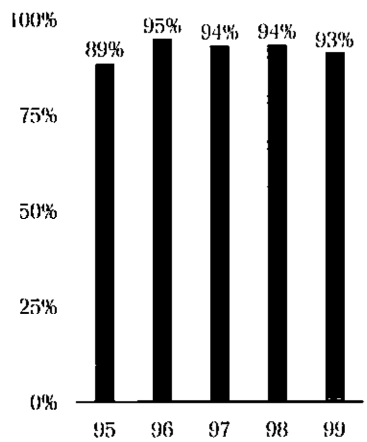
The Company has a bank credit agreement with First National Bank of Chicago, which provides a borrowing base of $20.0 million, subject to adequate oil and natural gas reserves. As of December 31, 1999, the balance outstanding on the line of credit is $9.3 million. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on December 31, 2002.

The Company closed four public drilling partnerships during 1999. The total amount received during 1999 was $36.1 million compared to $40.9 million for 1998. The Company closed its fourth program of 1999 on December 31, 1999 in the amount of $18.7 million and will drill the wells during the first quarter 2000. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum approximating 20% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

On January 29, 1999, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The Company purchased approximately $1.8 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1999. The Company utilized capital received from its 1997 public stock offering to fund this purchase.

On December 15, 1999, the Company purchased all of the working interest in 53 producing wells in the D-J Basin of Colorado. The Company estimates that the purchase includes proved developed reserves of approximately 3.6 Bcf of natural gas and 370,000 barrels of oil or approximately 5.8 Bcf equivalent (Bcfe), along with another 3.0 Bcfe of net development drilling locations. The total acquisition cost for the wells and locations was $5.2 million. The Company utilized part of its existing line of credit to fund the transaction. The effective date of the transaction was December 1, 1999.

Drilling Success Rate



The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

New Accounting Standards

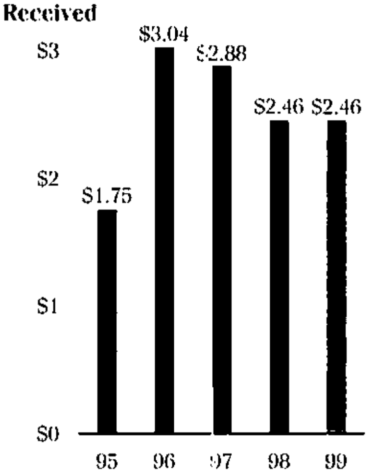
Statement of Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. SFAS No. 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. SFAS No. 133 is effective for years beginning after June 15, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and option contracts, outstanding at the date of adoption.

Quantitative and Qualitative Disclosure About Market Risk

Market-Sensitive Instruments and Risk Management

The Company's primary market risk exposures are interest rate risk and commodity price risk. These exposures are discussed in detail below:

Average Natural Gas Prices Received



Interest Rate Risk

The Company's exposure to market risk for changes in interest rates relates primarily to the Company's interest-bearing cash and cash equivalents and long-term debt. Interest-bearing cash and cash equivalents includes money market funds, certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 1999 is $9,992,700 with an average interest rate of 5.63 percent. As of December 31, 1999, the Company has long-term debt of $9,300,000 of which $6,300,000 is at a prime interest rate of 8.5% and $3,000,000 at a LIBOR interest rate of 7.73%.

Commodity Price Risk

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas futures contracts and option contracts. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates. As a result, while these hedging arrangements are structured to reduce the Company's exposure to decreases in price associated with the hedging commodity, they also limit the benefit the Company might otherwise have received from price increases associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes. As of December 31, 1999, PDC had entered into a series of natural gas future contracts and options contracts. Open future contracts maturing in 2000 are for the purchase of 1,820,000 MMBtu of natural gas with a weighted average price of $2.3725 MBtu resulting in a total contract amount of $4,317,950, and a fair market value of $350,500.

Independent Auditors' Report

The Stockholders and Board of Directors
Petroleum Development Corporation:

We have audited the accompanying consolidated balance sheets of Petroleum Development Corporation and subsidiaries as of December 31, 1999 and 1998, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 1999. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 1999 and 1998, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 1999, in conformity with generally accepted accounting principles.

KPMG LLP

Pittsburgh, Pennsylvania
March 6, 2000

Consolidated Balance Sheets
December 31, 1999 and 1998

ASSETS	1999	1998
Current assets:		
Cash and cash equivalents (includes restricted cash of $614,300 and $156,200, respectively)	$ 29,059,200	$ 34,894,600
Notes and accounts receivable	10,263,200	6,024,100
Inventories	577,600	702,400
Prepaid expenses	2,360,100	2,496,100
Total current assets	42,260,100	44,117,200
Properties and equipment:		
Oil and gas properties (successful efforts accounting method)	105,837,900	81,592,700
Pipelines	8,643,400	7,669,700
Transportation and other equipment	2,686,800	2,332,200
Land and buildings	1,181,000	1,152,700
	118,349,100	92,747,300
Less accumulated depreciation, depletion and amortization	31,207,300	27,356,700
	87,141,800	65,390,600
Other assets	2,681,700	1,901,200
	$ 132,083,600	$ 111,409,000

LIABILITIES AND STOCKHOLDERS' EQUITY	1999	1998
Current liabilities:		
Accounts payable	$ 14,678,900	$ 11,218,900
Accrued taxes	276,400	-
Other accrued expenses	2,643,700	1,959,900
Advances for future drilling contracts	25,137,400	28,320,800
Funds held for future distribution	2,027,600	984,200
Total current liabilities	44,764,000	42,483,800
Long-term debt	9,300,000	-
Other liabilities	3,160,600	2,233,500
Deferred income taxes	4,134,100	3,945,000
Commitments and contingencies		
Stockholders' equity:		
Common stock, par value $.01 per share: authorized 50,000,000 shares: issued and outstanding 15,737,795 and 15,510,762	157,400	155,100
Additional paid-in capital	32,071,000	31,873,100
Warrants outstanding	-	46,300
Retained earnings	38,496,500	30,672,200
Total stockholders' equity	70,724,900	62,746,700
	$132,083,600	$ 111,409,000

See accompanying notes to consolidated financial statements.

Consolidated Statements of Income
Years Ended December 31, 1999, 1998 and 1997

	1999	1998	1997
Revenues:			
Oil and gas well drilling operations	$ 42,115,600	$ 40,447,100	$ 34,405,400
Oil and gas sales	46,988,100	35,560,300	33,390,200
Well operations and pipeline income	5,314,500	4,581,000	4,509,300
Other income	2,392,400	2,385,200	1,573,100
	96,810,600	82,973,600	73,878,000
Costs and expenses:			
Cost of oil and gas well drilling operations	35,507,300	35,047,500	28,033,200
Oil and gas purchases and production cost	44,188,200	33,556,900	30,867,600
General and administrative expenses	2,801,000	2,490,500	2,318,800
Depreciation, depletion and amortization	4,031,200	3,253,600	2,660,300
Interest	182,400	-	315,900
	86,710,100	74,348,500	64,195,800
Income before income taxes	10,100,500	8,625,100	9,682,200
Income taxes	2,276,200	1,967,100	2,095,400
Net income	$ 7,824,300	$ 6,658,000	$ 7,586,800
Basic earnings per common share	$ .50	$ .43	$ .67
Diluted earnings per common and common equivalent share	$ .48	$ .41	$ .61

See accompanying notes to consolidated financial statements.

Consolidated Statements of Stockholders' Equity
Years Ended December 31, 1999, 1998 and 1997

	Common stock issued					
	Number of shares	Amount	Additional paid-in capital	Warrants outstanding	Retained earnings	Total
Balance December 31, 1996	10,460,753	$ 104,600	$ 6,540,500	$ -	$ 16,427,400	$ 23,072,500
Issuance of common stock:						
Stock offerings	4,577,500	45,800	24,903,600	46,300	-	24,995,700
Exercise of employee stock options	207,505	2,100	96,700	-	-	98,800
Amortization of stock award	12,300	-	12,300			
Net income	-	-	-	-	7,586,800	7,586,800
Balance December 31, 1997	15,245,758	$ 152,500	$ 31,553,100	$ 46,300	$ 24,014,200	$ 55,766,100
Issuance of common stock:						
Exercise of employee stock options	324,333	3,200	300,800	-	-	304,000
Amortization of stock award	-	-	12,200	-	-	12,200
Repurchase and cancellation of treasury stock	(59,329)	(600)	(303,400)	-	-	(304,000)
Income tax benefit from the exercise of stock options	-	-	310,400	-	-	310,400
Net income	-	-	-	-	6,658,000	6,658,000
Balance December 31, 1998	15,510,762	$ 155,100	$ 31,873,100	$ 46,300	$ 30,672,200	$ 62,746,700
Issuance of common stock:						
Exercise of employee stock options	324,333	3,200	300,800	-	-	304,000
Amortization of stock award	-	-	12,200	-		12,200
Repurchase and cancellation of treasury stock	(97,300)	(900)	(303,100)	-		(304,000)
Income tax benefit from the exercise of stock options	-	-	141,700	-		141,700
Warrants expired	-	-	46,300	(46,300)		
Net income	-	-	-	-	7,824,300	7,824,300
Balance December 31, 1999	15,737,795	$ 157,400	$ 32,071,000	$ -	$ 38,496,500	$ 70,724,900

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows
Years Ended December 31, 1999, 1998 and 1997

	1999	1998	1997
Cash flows from operating activities:			
Net income	$ 7,824,300	$ 6,658,000	$ 7,586,800
Adjustment to net income to reconcile to cash provided by operating activities:			
Deferred income taxes	108,900	244,000	107,700
Depreciation, depletion and amortization	4,031,200	3,253,600	2,660,300
(Gain) Loss from sale of assets	(501,800)	18,700	(39,600)
Disposition of leasehold acreage	618,100	196,200	187,200
Amortization of stock award	12,200	12,200	12,300
(Increase) decrease in notes and accounts receivable	(4,239,100)	(1,100,700)	1,772,600
Decrease (increase) in inventories	124,800	(404,500)	269,300
Decrease (increase) in prepaid expenses	312,600	(600)	(998,200)
(Increase) in other assets	(750,900)	(911,200)	(453,000)
Increase in accounts payable and accrued expenses	5,347,300	1,304,000	1,298,400
(Decrease) increase in advances for future drilling contracts	(3,183,400)	5,029,200	4,894,600
Increase (decrease) in funds held for future distribution	1,043,400	(675,500)	795,700
Total adjustments	2,923,300	6,965,400	10,507,300
Net cash provided by operating activities	10,747,600	13,623,400	18,094,100
Cash flows from investing activities:			
Capital expenditures	(27,758,200)	(26,629,700)	(13,675,100)
Proceeds from sale of leases	1,224,200	1,283,600	1,710,900
Proceeds from sale of fixed assets	651,000	56,300	87,600
Net cash used in investing activities	(25,883,000)	(25,289,800)	(11,876,600)
Cash flows from financing activities:			
Proceeds from debt	9,300,000	-	-
Proceeds from issuance of stock	-	-	25,048,100
Retirement of debt	-	-	(5,320,000)
Net cash provided by financing activities	9,300,000	-	19,728,100
Net (decrease) increase in cash and cash equivalents	(5,835,400)	(11,666,400)	25,945,600
Cash and cash equivalents, beginning of year	34,894,600	46,561,000	20,615,400
Cash and cash equivalents, end of year	$ 29,059,200	$ 34,894,600	$ 46,561,000

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements
Years Ended December 31, 1999, 1998 and 1997

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Petroleum Development Corporation and its wholly owned subsidiaries. All material intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its investment in limited partnerships under the proportionate consolidation method. Under this method, the Company's financial statements include its prorata share of assets and liabilities and revenues and expenses, respectively, of the limited partnerships in which it participates.

The Company is involved in three business segments. The segments are drilling and development, natural gas sales and well operations. (See Note 18)

The Company grants credit to purchasers of oil and gas and the owners of managed properties, substantially all of whom are located in West Virginia, Tennessee, Pennsylvania, Ohio, Michigan and Colorado.

Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Inventories

Inventories of well equipment, parts and supplies are valued at the lower of average cost or market. An inventory of natural gas is recorded when gas is purchased in excess of deliveries to customers and is recorded at the lower of cost or market.

Oil and Gas Properties

Exploration and development costs are accounted for by the successful efforts method.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Property acquisition costs are capitalized when incurred. Geological and geophysical costs and delay rentals are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered economically producible reserves. If reserves are not discovered, such costs are expensed as dry holes. Development costs, including equipment and intangible drilling costs related to both producing wells and developmental dry holes, are capitalized.

Unproved properties are assessed on a property-by-property basis and properties considered to be impaired are charged to expense when such impairment is deemed to have occurred.

Costs of proved properties, including leasehold acquisition, exploration and development costs and equipment, are depreciated or depleted by the unit-of-production method based on estimated proved developed oil and gas reserves.

Upon sale or retirement of complete units of depreciable or depletable property, the net cost thereof, less proceeds or salvage value, is credited or charged to income. Upon retirement of a partial unit of property, the cost thereof is charged to accumulated depreciation and depletion.

Based on the Company's experience, management believes site restoration, dismantlement and abandonment costs net of salvage to be immaterial in relation to operating costs. These costs are being expensed when incurred.

Transportation Equipment, Pipelines and Other Equipment

Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over useful lives of 3 to 17 years. These assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. An impairment loss based on estimated fair value is recorded when the review indicates that the related expected future net cash flow (undiscounted and without interest charges) is less than the carrying amount of the asset.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds applied thereto and any resulting gain or loss is reflected in income.

Buildings

Buildings are carried at cost and depreciated on the straight-line method over estimated useful lives of 30 years.

Advances for Future Drilling Contracts

Represents funds received from Partnerships and other joint ventures for drilling activities which have not been completed and accordingly have not yet been recognized as income in accordance with the Company's income recognition policies.

Retirement Plans

The Company has a 401-K contributory retirement plan (401-K Plan) covering full-time employees. The Company provides a discretionary matching of employee contributions to the plan.

The Company also has a profit sharing plan covering full-time employees. The Company's contributions to this plan are discretionary.

The Company has a deferred compensation arrangement covering executive officers of the Company as a supplemental retirement benefit.

The Company has established split-dollar life insurance arrangements with certain executive officers. Under these arrangements, advances are made to these officers equal to the premiums due. The advances are collateralized by the cash surrender value of the policies. The Company records as other assets its share of the cash surrender value of the policies.

Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

Income Taxes

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Derivatives

Gains and losses related to qualifying hedges of firm commitments or anticipated transactions through the use of natural gas futures and option contracts are deferred and recognized in income or as adjustments of carrying amounts when the underlying hedged transaction occurs. In order for futures contracts to qualify as a hedge, there must be sufficient correlation to the underlying hedged transaction. The change in the fair value of derivative instruments which do not qualify for hedging are recognized into income currently.

Stock Compensation

The Company has adopted SFAS No. 123, "Accounting for Stock-Based Compensation," which permits entities to recognize as expense over the vesting period the fair value of all stock-based awards on the date of grant. Alternatively, SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. See note 5 to the financial statements.

Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these financial statements in conformity with generally accepted accounting principles. Actual results could differ from those estimates. Estimates which are particularly significant to the consolidated financial statements include estimates of oil and gas reserves and future cash flows from oil and gas properties.

Reclassifications

Certain items and amounts reported in the 1998 and 1997 consolidated financial statements have been reclassified to conform to the current year's reporting format.

Fair Value of Financial Instruments

The carrying values and fair values of the Company's receivables, payables and debt obligations are estimated to be substantially the same as of December 31, 1999, 1998 and 1997.

New Accounting Standards

Statement of Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), was issued by the Financial Accounting Standards Board in June, 1998. SFAS No. 133 standardized the accounting for derivative instruments, including certain derivative instruments embedded in other contracts. SFAS No. 133 is effective for years beginning after June 15, 2000; however, early adoption is permitted. On adoption, the provisions of SFAS No. 133 must be applied prospectively. At the present time, the Company cannot determine the impact that SFAS No. 133 will have on its financial statements upon adoption, as such impact will be based on the extent of derivative instruments, such as natural gas futures and option contracts, outstanding at the date of adoption.

(2) NOTES AND ACCOUNTS RECEIVABLE

Included in other assets are noncurrent notes and accounts receivable as of December 31, 1999 and 1998, in the amounts of \$494,000 and \$617,900 net of the allowance for doubtful accounts of \$216,900 and \$129,800, respectively.

The allowance for doubtful current accounts receivable as of December 31, 1999 and 1998 was \$221,500 and \$144,800, respectively.

(3) LONG-TERM DEBT

On June 22, 1999 the Company executed an Amendment to its Credit Agreement with First National Bank of Chicago. The amendment provides a \$20.0 million borrowing base, subject to adequate oil and gas reserves. The Company has activated \$10.0 million of such borrowing base, and has at its discretion the ability to activate the additional \$10.0 million. The Company is required to pay a commitment fee of 1/4 percent on the unused portion of the activated credit facility. Interest accrues at prime, with LIBOR (London Interbank Market Rate) alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on December 31, 2002.

As of December 31, 1999 the outstanding balance was \$9,300,000 of which \$6,300,000 is at a prime rate of 8.5% and \$3,000,000 at a LIBOR rate of 7.73%. At December 31, 1998 there was no balance outstanding. Any amounts outstanding under the credit agreement are secured by substantially all properties of the Company. The credit agreement requires, among other things, the existence of satisfactory levels of natural gas reserves, maintenance of certain working capital and tangible net worth ratios along with a restriction on the payment of dividends.

(4) INCOME TAXES

The Company's provision for income taxes consisted of the following:

	1999	1998	1997
Current:			
Federal	$ 1,434,800	$ 1,197,800	$ 1,349,600
State	733,000	525,300	638,100
Total current income taxes	2,167,800	1,723,100	1,987,700
Deferred:			
Federal	(65,800)	(500)	(32,100)
State	174,200	244,500	139,800
Total deferred income taxes	108,900	244,000	107,700
Total taxes	$ 2,276,200	$ 1,967,100	$ 2,095,400

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 34 percent to pretax income from continuing operations as a result of the following:

	1999 Amount	1998 Amount	1997 Amount
Computed "expected" tax	$ 3,434,200	$ 2,932,500	$ 3,291,900
State income tax	598,300	508,100	513,400
Percentage depletion	(612,000)	(343,400)	(263,500)
Non-conventional source fuel credit	(846,300)	(696,700)	(846,400)
Adjustments to valuation allowance	(375,000)	(473,200)	(565,200)
Other	77,000	39,800	(34,800)
	$ 2,276,200	$ 1,967,100	$ 2,095,400

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 1999 and 1998 are presented below:

	1999	1998
Deferred tax assets:		
Allowance for doubtful accounts	$ 175,400	$ 108,600
Drilling notes	105,700	109,200
Alternative minimum tax credit carryforwards (Section 29)	1,982,300	1,783,000
Future abandonment	273,100	-
Deferred compensation	1,213,800	968,500
Other	51,600	148,300
Total gross deferred tax assets	3,801,900	3,117,600
Less valuation allowance	-	(375,000)
Deferred tax assets	3,801,900	2,742,600
Less current deferred tax assets (included in prepaid expenses)	(1,007,600)	(927,400)
Net non-current deferred tax assets	2,794,300	1,815,200
Deferred tax liabilities:		
Plant and equipment, principally due to differences in depreciation and amortization	(6,928,400)	(5,760,200)
Total gross deferred tax liabilities	(6,928,400)	(5,760,200)
Net deferred tax liability	$ (4,134,100)	$ (3,945,000)

The net changes in the total valuation allowance were decreases of $375,000, $473,200 and $782,300 for the years ended December 31, 1999, 1998 and 1997, respectively.

At December 31, 1999, the Company has alternative minimum tax credit carryforwards (Section 29) of approximately $1,982,300 which are available to reduce future federal regular income taxes over an indefinite period.

(5) COMMON STOCK

Options

Options amounting to 145,000, 20,000 and 500,000 shares were granted during 1999, 1998 and 1997, respectively, to certain employees and directors under the Company's Stock Option Plans. These options were granted with an exercise price equal to market value as of the date of grant and vest over a six month period for the 1999 grant and a two year period for the 1998 and 1997 grants. The outstanding options expire from 2000 to 2009.

The estimated fair value of the options granted during 1999, 1998 and 1997 was $2.44, $3.92 and $3.30 per option, respectively. The fair value was estimated using the Black-Scholes option pricing model with the following assumptions for the 1999, 1998 and 1997 grant, respectively: risk-free interest rate of 5.1%, 5.9% and 6.3%, expected dividend yield of 0%, expected volatility of 61.3%, 58.0% and 57.4% and expected life of 7 years.

	Number of Shares	Average Exercise Price	Range of Exercise Prices
Outstanding December 31, 1996	1,582,650	$ 0.94	.50 - 1.625
Granted	500,000	$ 5.13	5.13 - 5.13
Exercised	(210,000)	$ 0.58	.50 - 1.13
Expired	-	$ -	-
Outstanding December 31, 1997	1,872,650	$ 2.10	.94 - 5.13
Granted	20,000	$ 6.13	6.13 - 6.13
Exercised	(324,333)	$ 0.94	.94 - .94
Expired	-	$ -	-
Outstanding December 31, 1998	1,568,317	$ 2.39	.94 - 6.13
Granted	145,000	$ 3.75	3.75 - 3.75
Exercised	(324,333)	$ 0.94	.94 - .94
Expired	-	$ -	-
Outstanding December 31, 1999	1,388,984	$ 2.87	.94 - 6.13

As of December 31, 1999, there were 723,984 options outstanding and exercisable in the $.94 to $1.62 exercise price range which have a weighted average remaining contractual life of 2.7 years and weighted average exercise price of $1.05. Also as of December 31, 1999 there were 665,000 options outstanding and exercisable at a $3.75 to $6.13 exercise price range having a weighted average remaining contractual life of 7.9 years and weighted average exercise price of $4.86.

The Company accounts for its stock-based compensation plans under APB 25. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. Had compensation cost been determined under the provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	1999		1998	
	As Reported	Pro Forma	As Reported	Pro Forma
Net income	$ 7,824,300	$ 7,336,200	$ 6,658,000	$ 5,918,800
Basic earnings per share	$ .50	$ .47	$ .43	$ .38
Diluted earnings per share	$ .48	$ .45	$ .41	$ .37

Stock Redemption Agreement

The Company has stock redemption agreements with three officers of the Company. The agreements require the Company to maintain life insurance on each executive in the amount of $1,000,000. The agreements provide that the Company shall utilize the proceeds from such insurance to purchase from such executives' estates or heirs, at their option, shares of the Company's stock. The purchase price for the outstanding common stock is to be based upon the average closing asked price for the Company's stock as quoted by NASDAQ during a specified period. The Company is not required to purchase any shares in excess of the amount provided for by such insurance.

Stock Offerings

In September 1997, the Company completed a private offering of Common Stock pursuant to which it issued and sold 500,000 shares at a price of $4.00 per share and issued warrants for 125,000 shares of Common Stock exercisable during a two-year period ending September 15, 1999 at an exercise price of $6.00 per share, resulting in proceeds to the Company of $2.0 million. The warrants were not exercised and expired on September 15, 1999. No registration rights were granted in connection with the securities issued in this offering.

In November 1997, the Company completed a public offering of 4,077,500 shares of its Common Stock at a price of $6.25 per share. Net proceeds to the Company of approximately $23 million from the sale of common stock was designated to fund development drilling on new and existing properties, potential acquisition of producing properties and general corporate purposes, including working capital and possible acquisitions of complementary businesses.

(6) EMPLOYEE BENEFIT PLANS

The Company made 401-K Plan contributions of $217,400, $202,600 and $171,300 for 1999, 1998 and 1997, respectively.

The Company has a profit sharing plan (the Plan) covering full-time employees. The Company contributed $47,000, $17,000 and $15,500, to the plan in cash during 1999, 1998 and 1997, respectively.

During 1999, 1998 and 1997 the Company expensed and established a liability for $90,000 each year under a deferred compensation arrangement with the executive officers of the Company.

In 1995, a total of 90,000 restricted shares of the Company's common stock were granted to certain employees and available to them upon retirement. The market value of shares awarded was $101,300. This amount was recorded as unamortized stock award. The unamortized stock award is being amortized to expense over the employees' expected years to retirement and amounted to $12,200, $12,200 and $12,300 in 1999, 1998 and 1997, respectively.

At December 31, 1999 and 1998, the Company has recorded as other assets $300,000 and $240,000, respectively as its share of the cash surrender value of the life insurance pledged as collateral for the payment of premiums on split-dollar life insurance policies owned by certain executive officers.

(7) EARNINGS PER SHARE

Basic earnings per share is based on the weighted average number of common share outstanding of 15,734,063 for 1999, 15,505,680 for 1998, and 11,278,800 for 1997.

Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding of 16,286,852 for 1999, 16,338,298 for 1998 and 12,540,165 for 1997. Stock options are considered to be common stock equivalents and, to the extent appropriate, have been added to the weighted average common shares outstanding.

(8) TRANSACTIONS WITH AFFILIATES

As part of its duties as well operator, the Company received $24,002,500 in 1999, $22,997,300 in 1998 and $22,985,400 in 1997 representing proceeds from the sale of oil and gas and made distributions to investor groups according to their working interests in the related oil and gas properties. The Company provided oil and gas well drilling services to affiliated partnerships, substantially all of the Company's oil and gas well drilling operations was for such partnerships. The Company also provided related services of operation of wells, reimbursement of syndication costs, management fees, tax return preparation and other services relating to the operation of the partnerships. The Company received $10,322,500 in 1999, $9,621,700 in 1998 and $8,113,000 in 1997 for those services.

During 1999, 1998 and 1997, the Company paid $31,600, $30,000 and $63,800, respectively to the Corporate Secretary's law firm for various legal services.

(9) COMMITMENTS AND CONTINGENCIES

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities and industrial customers. No customer accounted for more than 10.0% of total revenues in 1999 or 1998. One customer, Hope Gas, Inc., a regulated public utility accounted for 12.0% of total revenue in 1997.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may tender their partnership units for repurchase at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if such units are tendered, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if tendered by the investors, is currently approximately $759,000. The Company has adequate capital to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

(10) SUPPLEMENTAL DISCLOSURE OF CASH FLOWS

The Company paid $124,200, $0, and $380,000 for interest in 1999, 1998 and 1997, respectively. The Company paid income taxes in 1999, 1998 and 1997 in the amounts of $1,327,800, $2,349,100 and $1,932,500, respectively.

(11) ACQUISITIONS

On February 19, 1998, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1993. The Company purchased approximately $2.3 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1998. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On June 12, 1998 the Company purchased for $3.1 million a majority interest in the assets of Pemco Gas, Inc., a Pennsylvania producing company. The assets include 122 natural gas wells, 2,700 undeveloped acres, gathering systems, natural gas compressors and other facilities. The Company estimates that its interest includes 4.7 Bcf of natural gas reserves. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On November 16, 1998, the Company purchased all of the working interest in a 13 well Antrim Shale production unit and adjacent development locations in Montmorency County, Michigan. The Company estimates that the purchase includes approximately 4 Bcf of proved developed producing reserves and 1.5 Bcf of proved undeveloped reserves, with an acquisition cost of approximately $2.8 million. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On January 29, 1999, the Company offered to purchase from Investors their units of investment in the Company's Drilling Programs formed prior to 1996. The Company purchased approximately $1.8 million of producing oil and gas properties in conjunction with this offer, which expired on March 31, 1999. The Company utilized capital received from its Public Stock Offering to fund this purchase.

On December 15, 1999, the Company purchased all of the working interest in 53 producing wells in the D-J Basin of Colorado. The Company estimates that the purchase includes proved developed reserves of approximately 3.6 Bcf of natural gas and 370,000 barrels of oil or approximately 5.8 Bcf equivalent (Bcfe), along with another 3.0 Bcfe of proved undeveloped reserves. Also included in the acquisition was 16.5 net development drilling locations. The total acquisition cost for the wells and locations was $5.2 million. The Company utilized part of its existing line of credit to fund the transaction. The effective date of the transaction was December 1, 1999.

(12) DERIVATIVES AND HEDGING ACTIVITIES

The Company utilizes commodity based derivative instruments as hedges to manage a portion of its exposure to price volatility stemming from its integrated natural gas production and marketing activities. These instruments consist of natural gas futures and option contracts traded on the New York Mercantile Exchange. The futures and option contracts hedge committed and anticipated natural gas purchases and sales, generally forecasted to occur within a 12 month period. The Company does not hold or issue derivatives for trading or speculative purposes.

As of December 31, 1999 and 1998, the Company had futures contracts for the purchase of $4,318,000 and $1,120,300 of natural gas, respectively. While these contracts have nominal carrying value, their fair value, represented by the estimated amount that would be received upon termination of the contracts, based on market quotes, was a net value of $350,500 at December 31, 1999 and ($105,400) at December 31, 1998.

The Company is required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 1999 and 1998, cash in the amount of $614,300 and $156,200 was on deposit.

(13) COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred by the Company in oil and gas property acquisition, exploration and development are presented below:

	Years Ended December 31, 1999	1998	1997
Property acquisition cost:			
Proved undeveloped properties	$ 2,532,200	$ 1,903,200	$ 3,109,000
Producing properties	6,997,500	8,679,000	85,100
Development costs	17,168,000	14,902,500	9,863,200
	$ 26,697,700	$ 25,484,700	$ 13,057,300

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells and to provide facilities to extract, treat, gather and store oil and gas.

(14) OIL AND GAS CAPITALIZED COSTS

Aggregate capitalized costs for the Company related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	December 31, 1999	1998
Proved properties:		
Tangible well equipment	$ 62,996,900	$ 46,722,500
Intangible drilling costs	36,270,300	28,379,200
Well equipment leased to others	4,063,600	4,063,600
Undeveloped properties	2,507,100	2,427,400
	105,837,900	81,592,700
Less accumulated depreciation, depletion and amortization	23,652,000	20,395,400
	$ 82,185,900	$ 61,197,300

(15) RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The results of operations for oil and gas producing activities (excluding marketing) are presented below:

	Years Ended December 31, 1999	1998	1997
Revenue:			
Oil and gas sales	$ 8,628,400	$ 6,121,700	$ 5,363,600
Expenses:			
Production costs	2,422,000	1,516,700	1,206,000
Depreciation, depletion and amortization	3,220,900	2,392,000	1,629,900
	5,642,900	3,908,700	2,835,900
Results of operations for oil and gas producing activities before provision for income taxes	2,985,500	2,213,000	2,527,700
Provision for income taxes	469,400	398,600	567,800
Results of operations for oil and gas producing activities (excluding corporate over-head and interest costs)	$ 2,516,100	$ 1,814,400	$ 1,959,900

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including such costs as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and other production taxes. In addition, production costs include administrative expenses and depreciation applicable to support equipment associated with these activities.

Depreciation, depletion and amortization expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment.

The provision for income taxes is computed at the statutory federal income tax rate and is reduced to the extent of permanent differences, such as investment tax and non-conventional source fuel tax credits and statutory depletion allowed for income tax purposes.

(16) NET PROVED OIL AND GAS RESERVES (UNAUDITED)

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineer, Wright & Company, Inc. at December 31, 1999, 1998 and 1997. These reserves have been prepared in compliance with the Securities and Exchange Commission rules based on year end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Oil (Bbls) 1999	1998	1997
Proved developed and undeveloped reserves:			
Beginning of year	29,000	45,000	81,000
Revisions of previous estimates	67,000	(10,000)	(27,000)
Beginning of year as revised	96,000	35,000	54,000
New discoveries and extensions	404,000	-	-
Dispositions	-	-	-
Acquisitions	662,000	2,000	-
Production	(8,000)	(8,000)	(9,000)
End of year	1,154,000	29,000	45,000
Proved developed reserves:			
Beginning of year	29,000	45,000	81,000
End of year	798,000	29,000	45,000

	Gas (Mcf) 1999	1998	1997
Proved developed and undeveloped reserves:			
Beginning of year	80,819,000	57,243,000	43,312,000
Revisions of previous estimates	(4,475,000)	(3,517,000)	875,000
Beginning of year as revised	76,344,000	53,726,000	44,187,000
New discoveries and extensions	24,781,000	23,552,000	2,489,000
Dispositions to partnerships	(8,774,000)	(6,009,000)	-
Acquisitions, net of sales to partnerships in 1997	12,345,000	12,003,000	12,377,000
Production	(3,451,000)	(2,453,000)	(1,810,000)
End of year	101,245,000	80,819,000	57,243,000
Proved developed reserves:			
Beginning of year	64,562,000	42,411,000	35,516,000
End of year	82,628,000	64,562,000	42,411,000

(17) STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL AND GAS RESERVES (UNAUDITED)

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

	Years Ended December 31, 1999	1998	1997
Future estimated cash flows	$ 307,816,000	$ 186,598,000	$ 159,618,000
Future estimated production and development costs	(129,557,000)	(95,670,000)	(69,265,000)
Future estimated income tax expense	(39,930,000)	(20,322,000)	(20,781,000)
Future net cash flows	138,329,000	70,606,000	69,572,000
10% annual discount for estimated timing of cash flows	(79,875,000)	(40,412,000)	(41,636,000)
Standardized measure of discounted future estimated net cash flows	$ 58,454,000	$ 30,194,000	$ 27,936,000

The following table summarizes the principal sources of change in the standardized measure of discounted future estimated net cash flows:

	Years Ended December 31, 1999	1998	1997
Sales of oil and gas production, net of production costs	$ (6,206,000)	$ (4,605,000)	$ (4,158,000)
Net changes in prices and production costs	29,547,000	(23,083,000)	(63,573,000)
Extensions, discoveries and improved recovery, less related cost	39,653,000	18,615,000	3,705,000
Dispositions to partnerships	(6,152,000)	(5,762,000)	-
Acquisitions, net of sales to partnerships in 1997	31,915,000	13,938,000	13,299,000
Development costs incurred during the period	17,168,000	14,903,000	9,863,000
Revisions of previous quantity estimates	(4,944,000)	(5,605,000)	2,332,000
Changes in estimated income taxes	(19,608,000)	459,000	12,718,000
Changes in discount	(39,463,000)	1,224,000	24,597,000
Changes in production rates (timing) and other	(13,650,000)	(7,826,000)	(5,109,000)
	$ 28,260,000	$ 2,258,000	$ (6,326,000)

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

(18) BUSINESS SEGMENTS (THOUSANDS)

PDC's operating activities can be divided into three major segments: drilling and development, natural gas sales, and well operations. The Company drills natural gas wells for Company-sponsored drilling partnerships and retains an interest in each well. The Company also engages in oil and gas sales to residential, commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31, 1999, 1998 and 1997 is as follows:

	1999	1998	1997
REVENUES			
Drilling and Development	$ 42,116	$ 40,447	$ 34,406
Natural Gas Sales	46,988	35,560	33,390
Well Operations	5,314	4,581	4,509
Unallocated amounts (1)	2,392	2,385	1,573
Total	$ 96,810	$ 82,973	$ 73,878

(1) Includes interest on investments, partnership management fees and gain on sale of assets in 1999 which are not allocated in assessing segment performance.

	1999	1998	1997
SEGMENT INCOME BEFORE INCOME TAXES			
Drilling and Development	$ 6,608	$ 5,400	$ 6,372
Natural Gas Sales	2,967	2,064	2,780
Well Operations	1,219	1,372	1,701
Unallocated amounts (2)			
General and Administrative expenses	(2,801)	(2,491)	(2,660)
Interest expense	(182)	-	(316)
Other (1)	2,289	2,280	1,805
Total	$ 10,100	$ 8,625	$ 9,682

(2) Items which are not allocated in assessing segment performance.

	1999	1998	1997
Segment Assets			
Drilling and Development	$ 23,957	$ 27,288	$ 22,110
Natural Gas Sales	93,073	65,256	45,888
Well Operations	7,977	7,136	5,953
Unallocated amounts			
Cash	1,967	7,814	20,942
Other	4,934	3,806	3,519
Total	$ 131,908	$ 111,300	$ 98,412

	1999	1998	1997
Expenditures For Segment Long-Lived Assets			
Drilling and Development	$ 1,710	$ 1,953	$ 2,862
Natural Gas Sales	24,613	23,645	10,207
Well Operations	1,328	947	505
Unallocated amounts	107	85	101
Total	$ 27,758	$ 26,630	$ 13,675

(19) QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 1999 and 1998, are as follows:

	1999				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$ 27,666,300	$ 21,064,000	$ 23,841,700	$ 24,238,600	$ 96,810,600
Cost of operations	23,837,400	18,411,200	20,038,900	21,439,200	83,726,700
Gross profit	3,828,900	2,652,800	3,802,800	2,799,400	13,083,900
General and administrative expenses	464,400	595,800	859,200	881,600	2,801,000
Interest expense	-	-	88,100	94,300	182,400
	464,400	595,800	947,300	975,900	2,983,400
Income before income taxes	3,364,500	2,057,000	2,855,500	1,823,500	10,100,500
Income taxes	753,700	460,700	842,000	219,800	2,276,200
Net income	$ 2,610,800	$ 1,596,300	$ 2,013,500	$ 1,603,700	$ 7,824,300
Basic earnings per share	$ .17	$ .10	$ .13	$ .10	$ .50
Diluted earnings per share	$ .16	$ .10	$ .12	$ .10	$ .48

	1998				
	Quarter				Year
	First	Second	Third	Fourth	
Revenues	$ 25,247,400	$ 19,161,600	$ 16,649,400	$ 21,915,200	$ 82,973,600
Cost of operations	21,203,300	16,328,500	15,157,200	19,169,000	71,858,000
Gross profit	4,044,100	2,833,100	1,492,200	2,746,200	11,115,600
General and administrative expenses	440,100	611,000	731,600	707,800	2,490,500
Interest expense	-	-	-	-	-
	440,100	611,000	731,600	707,800	2,490,500
Income before income taxes	3,604,000	2,222,100	760,600	2,038,400	8,625,100
Income taxes	807,300	497,700	180,400	481,700	1,967,100
Net income	$ 2,796,700	$ 1,724,400	$ 580,200	$ 1,556,700	$ 6,658,000
Basic earnings per share	$ .18	$ .11	$ .04	$ .10	$ .43
Diluted earnings per share	$ .17	$ .11	$ .03	$ .10	$ .41

Cost of operations include cost of oil and gas well drilling operations, oil and gas purchases and production costs and depreciation, depletion and amortization.

Stock Price History and Data

The common stock of the Company is traded in the over-the-counter market under the symbol PETD. The following table sets forth, for the periods indicated, the high and low bid quotations per share of the Company's common stock in the over-the-counter market, as reported by the National Quotation Bureau Incorporated. These quotations represent inter-dealer prices without retail markups, markdowns, commissions or other adjustments and may not represent actual transactions.

	High	Low
1998		
First Quarter	6 5/8	4 1/8
Second Quarter	6 1/2	4 13/16
Third Quarter	5 1/2	3 5/16
Fourth Quarter	5 3/8	2 15/16
1999		
First Quarter	3 15/16	2 7/8
Second Quarter	4 11/16	3 5/16
Third Quarter	5 3/8	4 3/16
Fourth Quarter	4 13/16	3 23/32

As of December 31, 1999, there were approximately 1,349 record holders of the Company's common stock.

The Company has not paid any dividends on its common stock and currently intends to retain earnings for use in its business. Therefore, it does not expect to declare cash dividends in the foreseeable future. Further, the Company's Credit Agreement restricts the payment of dividends.

Corporate Information

Corporate Offices

Petroleum Development Corporation
Post Office Box 26
103 East Main Street
Bridgeport, West Virginia 26330
304.842.6256
304.842.0913 fax
www.petd.com

Field Offices

Petroleum Development Corporation
11911 US 23
Ossinke, Michigan 49766
517.471.2004

Petroleum Development Corporation
1313 Denver Avenue, Building 3
Fort Lupton, Colorado 80621
303.857.7893

Petroleum Development Corporation
633 West Main Street
Bridgeport, West Virginia 26330
304.842.5002

Petroleum Development Corporation
1179 Water Street
Indiana, Pennsylvania 15701
724.465.0149

Paramount Natural Gas
63 Gallagher Avenue
Logan, Ohio 43138
740.385.8583

Directors and Officers

James N. Ryan
Chairman and Chief Executive Officer

Steven R. Williams
President and Director

Dale G. Rettinger
Chief Financial Officer
and Executive Vice President
Treasurer and Director

Ersel E. Morgan
Vice President Production

Thomas E. Riley
Vice President Business Development

Eric R. Stearns
Vice President Exploration
and Development

Darwin L. Stump
Controller

Roger J. Morgan
Secretary and Director

Vincent F. D'Annunzio
Director

Donald B. Nestor
Director

Jeffrey C. Swoveland
Director

Glossary of Terms Used in this Annual Report

Bbl(s)	Barrel(s) of oil. One barrel of oil is equal to the energy equivalent of six Mcf of natural gas.
Bcf	Billion cubic feet of natural gas
Bcfe	Billion cubic feet of natural gas equivalent
EBITDA	Earnings before interest expense, income taxes, depreciation, depletion and amortization. A cash flow financial measure commonly used in the oil and gas industry.
MBbl	Thousand barrels of oil
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent of natural gas
MMBbl	Million barrels of oil
MMBoe	Million barrels of oil equivalent
MMcf	Million cubic feet of natural gas
MMcfe	Million cubic feet of natural gas equivalent
SEC PV-10	The value of proved reserves based on year-end commodity prices, discounted at 10 percent.
Tcfe	Trillion cubic feet equivalent

Auditors

KPMG LLP
Certified Public Accountants
Pittsburgh, Pennsylvania

Legal Counsel

Duane, Morris and Heckscher
Washington, District of Columbia

Young, Morgan & Cann
Clarksburg, West Virginia

Transfer Agent

Transfer Online
227 Pine Street, Suite 300
Portland, Oregon 97204

Contact for information regarding changes of address, registration of shares, transfers or lost certificates, or for information about your shareholder account.

Form 10-K

A copy of the Annual Report of Petroleum Development Corporation to the Securities Exchange Commission (Form 10-K) may be obtained by writing to the company.

Independent Reservoir Engineers

Wright & Company, Inc.
Nashville, Tennessee

Stock Exchange Listing

The company's common stock trades on The NASDAQ Stock Market™ under the symbol "PETD."

Petroleum Development Corporation
103 East Main Street, P.O. Box 26, Bridgeport, WV 26330
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