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82- SUBMISSIONS FACING SHEET

Follow-Up Materials

MICROFICHE CONTROL LABEL

REGISTRANT'S NAME APF Energy Trust

*CURRENT ADDRESS

**FORMER NAME

PROCESSED

**NEW ADDRESS

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OICF/BY: dlw

DATE : 6/13/02

APF ENERGY TRUST

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2001

May 17, 2002

APF Energy Trust
2100, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 294-1000 Toll Free: (800) 838-9206 Fax: (403) 294-1074
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ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"ARC"	Alberta Royalty Credit	**"bcf"**	1,000,000,000 cubic feet
"bbls"	barrels	**"mcf/d"**	one thousand cubic feet per day
"mbbl"	1,000 barrels	**"mmcf/d"**	one million cubic feet per day
"bbl/d"	barrels per day	**"mmbtu"**	one million BTUs
"Gj"	Gigajoule = 0.95 mcf	**"boe"**	barrels of oil equivalent (6 mcf = 1 boe)
"m^3"	cubic metre volume	**"mboe"**	1,000 barrels of oil equivalent
"NGL"	natural gas liquids	**"boe/d"**	barrels of oil equivalent per day
"mcf"	1,000 cubic feet	**"BTU"**	British thermal unit
"mmcf"	1,000,000 cubic feet		

ADDITIONAL INFORMATION

Additional information, including Directors' and Executive Officers' remuneration, principal holders of the Trust's securities and options to purchase the Trust's securities, and interest of insiders in material transactions is contained in the Trust's Management Information Circular dated April 18, 2002 in connection with the Annual General and Special Meeting of Unitholders of the Trust to be held on June 3, 2002 which information is incorporated herein by reference. Additional financial information and discussion of the affairs of the Trust and the business environment in which the Trust operates is provided in the Trust's Management Discussion and Analysis and comparative consolidated financial statements for the most recently completed fiscal year ended December 31, 2001 found on pages 18 to 22 and 23 to 38 respectively, of the 2001 Annual Report to the Unitholders, which information is incorporated herein by reference.

The Trust will provide to any person upon request to the Manager:

1. When the Trust is in the course of a distribution pursuant to a prospectus or preliminary prospectus that has been filed:
   (a) One copy of this Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated herein by reference;
   (b) One copy of the comparative consolidated financial statements of the Trust and the Corporation for the year ended December 31, 2001, together with the report of the auditors thereon, and one copy of any interim financial statement of the Trust issued subsequent to the annual financial statements;
   (c) One copy of the Management Information Circular and Proxy of the Trust dated April 18, 2002, in connection with the Annual General and Special Meeting of the Unitholders of the Trust to be held on June 3, 2002;
   (d) One copy of any other document or report which is incorporated by reference into the prospectus or preliminary prospectus and is not required to be provided under (a) and (c) above; or

2. At any other time, one copy of any other document referred to in paragraphs 1(a), (b) and (c) above, provided that the company may require the payment of a reasonable charge from such person or company who is not a Unitholder of the Trust.

SPECIAL NOTE REGARDING FORWARD LOOKING INFORMATION

Certain statements in this document or incorporated herein by reference may constitute "forward-looking statements". These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects" or words of a similar nature. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, the following: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the ability of the Company to complete its capital programs; successful negotiations with bankers and other third parties; the success of exploration and development activities; production levels; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); site restoration costs; and other circumstances affecting revenues and expenses.

INCORPORATION

APF Energy Trust

APF Energy Trust ("the Trust") is an open-ended investment trust. It was created pursuant to a Trust Indenture dated as of October 10, 1996, as amended, between the Corporation and The Trust Company of Bank of Montreal (the "Trustee") to issue trust units to the public and to acquire a royalty from APF Energy Inc. (the "Corporation") consisting of 99% of the cash flow from the Corporation's producing oil and gas properties. The Corporation and the Trust are managed by APF Energy Management Inc. (the "Manager"), whose management team has extensive oil and gas management and operations experience. The office of the Trust, the Corporation and the Manager is located at Suite 2100, 144 – 4th S.W., Calgary, Alberta T2P 3N4. The Trust Units of the Trust are listed and posted for trading on The Toronto Stock Exchange under the symbol "AY.UN".

The Corporation

The Corporation was incorporated pursuant to the *Business Corporations Act* (Alberta) on December 8, 1995 as 677633 Alberta Inc. By Articles of Amendment filed May 8, 1996, the Corporation's name was changed to APF Energy Inc. The Corporation was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty to the Trust. Pursuant to a take-over bid completed on April 17, 1997, the Corporation acquired all of the outstanding common shares of Bayridge Resources Limited ("Bayridge") for cash. On May 1, 1997, the Corporation amalgamated with Bayridge and continued under the name of APF Energy Inc. On April 11, 2001, the Corporation acquired 98.86% of the shares of Alliance Energy Inc. ("Alliance"). The Corporation subsequently acquired the remaining Alliance shares pursuant to the compulsory acquisition procedures of the Business Corporations Act (Alberta) and on May 1, 2001, the Corporation amalgamated with Alliance and continued under the name of APF Energy Inc.

APF Energy Management Inc.

The Manager was incorporated under the *Canada Business Corporations Act* on September 12, 1994 as Skyridge Resources Inc., and changed its name to APF Energy Management Inc. by Articles of Amendment filed June 6, 1996. The senior officers of the Manager have been involved in all aspects of managing and operating private and public oil and natural gas entities. The Manager currently owns interests in oil and natural gas properties in Alberta. It is also engaged in other types of energy-related management and advisory activities. Oil and natural gas properties may occasionally be made available for purchase in areas where the Manager or its clients, other than the Corporation, hold interests. In such circumstances, the Manager will provide each of its clients, including the Corporation, with the opportunity to participate in the acquisition of such properties in the proportion that each of its clients has funds available for such acquisition. Any joint acquisition will require approval by a majority of the Corporation's board of directors, which is comprised of three independent directors elected by Unitholders and two nominees of the Manager.

ORGANIZATION OF THE TRUST

The Trust Indenture

A maximum of 500 million Trust Units have been created and may be issued pursuant to the Trust Indenture. The Trust Units represent beneficial interests in the Trust. All Trust Units share equally in all distributions from the Trust and all Trust Units carry equal voting rights at meetings of Unitholders.

Business Objectives

The goal of the Manager, on behalf of the Trust and the Corporation, is to provide the Unitholders with high and stable cash contributions. To achieve this, the Corporation must continually replace and add reserves through acquisitions, drilling and optimization initiatives.

In order to replace reserves and achieve growth, the Manager must be able to identify, evaluate and acquire oil and gas properties. To date, the Manager has demonstrated an ability to complete acquisitions on favourable terms, which have resulted in high and stable distributions for Unitholders since the inception of the Trust. On a go forward basis, the Manager will continue to use its internal expertise to identify potential acquisitions, but will also rely on financial advisors and other industry sources who are able to present opportunities. The ability of the Corporation to complete these acquisitions will depend on its available credit facilities and on the Trust being able to raise equity from time to time.

Meetings and Voting

The Trust Indenture provides that annual meetings of the Unitholders shall be held. Special meetings of Unitholders may be called at any time by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

Unitholders may attend and vote at all meetings of such holders either in person or by proxy and a proxyholder need not be a holder of Trust Units. Two persons present in person or represented by proxy and representing in the aggregate not less than 10% of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all such meetings.

Unitholders are entitled to one vote per Trust Unit at all meetings of Unitholders called pursuant to the Trust Indenture. A special resolution is required to, among other things, substantively amend the Trust Indenture, remove the Trustee or terminate the Trust. A special resolution is also required to make substantive amendments to the material contracts of the Trust and to sell or agree to sell the property of the Trust (including the Royalty) as an entirety or substantially as an entirety.

"Open-end" Status

Effective July 28, 1999, the Trust was converted to an open-end trust (the "Conversion"). The Manager proposed the Conversion as it believed it would provide the Trust with greater flexibility in the future to make value-enhancing acquisitions. The investments that may be made by the Trust were expanded from the acquisition and holding of royalties on petroleum and natural gas properties and related assets to include the acquisition and holding of various forms of energy-related assets (for example, the shares of an oil and gas company or petroleum and natural gas related facilities without associated properties, energy marketing companies or assets or midstream or downstream companies) and the securities of entities holding such assets (which may include securities of a trust or securities of a wholly-owned subsidiary corporation).

To date, the Trust has only participated in the Royalty granted by the Corporation on the Properties and has invested in promissory notes issued from time to time by the Corporation and certain permitted investments. The Royalty consists of an entitlement to 99% of the Royalty Income earned by the Corporation.

Redemption Right

A Unitholder may require the Trust, at any time on the demand of the Unitholder, to redeem his or her Trust Units. Upon such redemption, all of such Unitholder's rights to and under the Trust Units tendered for redemption are surrendered and the Unitholder is entitled to receive a price per Trust Unit based on a market price formula, subject to a monthly aggregate cash cap for all Trust Units tendered for redemption in such month of $100,000 and an aggregate cash cap for all Trust Units tendered for redemption in a six month period of $500,000. The Board of Directors of the Corporation may waive these limitations and shall waive them in circumstances where Trust Units held in trusts governed by registered plans under the *Income Tax Act* would not otherwise be entitled to receive cash payment for the Trust Units redeemed. The price payable by the Trust on retraction may be satisfied by way of a cash payment or, in certain circumstances, including where such payment would cause the monthly or six month cash cap to be exceeded, by way of an *in specie* distribution (that is, a proportionate distribution of the assets of the Trust).

Distributable Income

Unitholders of record on a record date are entitled to receive monthly cash distributions of Distributable Income for the applicable production month. Distributable Income is paid by the Trustee to the Unitholders 15 days following the applicable record date.

Distributions

The Trust distributes cash to Unitholders on a monthly basis. During 1997 (the first year during which the Trust made distributions), 60.5% of cash distributions were tax deferred and for income tax purposes were treated as a return of capital, while the same figures for 1998, 1999 and 2000 were 75%, 66% and 38% respectively. For 2001 cash distributions, 42.8% were not subject to tax with 57.2% being taxable to Unitholders.

In the past, the Trust has not paid out 100% of Distributable Income to Unitholders, retaining a portion as is reasonably determined by the Manager to, among other things, fund capital expenditure or acquisitions, stabilize future distributions or advance funds to the Corporation to temporarily reduce its indebtedness to its bankers.

The following per Trust Unit cash distributions have been received by Unitholders during the periods indicated:

Trust Unit Cash Distributions

1997	$1.510
1998	$1.840
1999	$1.555
2000	$1.900
2001	
January 15	$0.220
February 15	$0.250
March 15	$0.250
April 15	$0.225
May 15	$0.300
June 15	$0.300
July 15	$0.300
August 15	$0.300
September 15	$0.250
October 15	$0.250
November 15	$0.200
December 15	$0.200
2001 Total	$3.045
2002	
January 15	$0.150
February 15	$0.150
March 15	$0.150
April 15	$0.150
May 15	$0.150
Total	$10.60

Note:

(1) The initial public offering of the Trust was completed on December 17, 1996. The first cash distribution was made to Unitholders on January 31, 1997.

Corporate Governance

In general, the Corporation has been delegated the significant management decisions of the Trust. The Unitholders are entitled to elect a majority of the Corporation's Board of Directors pursuant to the terms of a unanimous shareholder agreement. Subject to the ultimate authority of the Corporation's Board of Directors, the Corporation and the Trust are managed by the Manager. Pursuant to a royalty agreement, substantially all of the economic benefit derived from the assets of the Corporation accrues to the benefit of the Trust and ultimately to the Unitholders.

The Corporation has a board of directors consisting of five individuals, three of who are independent directors, and two of whom were elected by the Manager.

The Manager

Business of the Manager

The Manager was incorporated under the *Canada Business Corporations Act* on September 12, 1994 as Skyridge Resources Inc. By Articles of Amendment filed June 6, 1996, the Manager changed its name to APF Energy Management Inc. The registered and principal business address of the Manager is Suite 2100, 144 – 4th S.W., Calgary, Alberta T2P 3N4.

The Manager provides management, administrative and advisory services to the Trust and the Corporation pursuant to management agreements. The Manager currently has 43 employees.

Compensation of the Manager

The Manager, through its ownership of 100% of the shares of the Corporation, is entitled to receive 1% of the Royalty Income derived from the Properties. In addition, the Manager is entitled to be compensated as follows for providing services to the Trust and to the Corporation.

Management Fees

Pursuant to a management agreement, the Manager receives a management fee, payable monthly, equal to 3.5% of the sum of net production revenue (less Crown royalties) and the ARC attributable to the Properties. Pursuant to the management agreement respecting the Trust, the Manager receives an annual management fee of $100, payable at the end of each calendar year. The Manager was paid $1.5 million in management fees for the year ended December 31, 2001 ($1.0 million for the year ended December 31, 2000).

General and Administrative Costs

The Manager is also entitled to reimbursement for G&A. G&A is, generally, charged to the Corporation by the Manager in proportion to the Corporation's share, on a boe basis, of all the oil and natural gas production under the administration of the Manager. Costs and expenses including, without limitation, management time, incurred by the Manager in connection with the design and implementation of exploitation and development programs, are charged on an actual time expended basis. The Manager was reimbursed $2.2 million for G&A for the year ended December 31, 2001 ($1.5 million for the year ended December 31, 2000).

Structuring Fee

The Manager is entitled to earn a structuring fee of 1.5% of the costs of any future acquisitions or proceeds of divestitures by the Corporation of interests in the Properties, provided that no such fee shall be payable on the disposition of any Properties which have been acquired within one year of such disposition nor on Properties acquired with the proceeds of a divestiture on which the structuring fee has previously been paid. The Manager was paid $1.6 million in connection with the acquisition of Properties for the year ended December 31, 2001 ($0.3 million for the year ended December 31, 2000).

GENERAL DEVELOPMENT OF THE BUSINESS

Since it commenced business in 1996, the Corporation has acquired petroleum and natural gas assets in Western Canada in a number of transactions. The most significant of these are summarized below:

Date	Transaction
September 1996	Acquisition from Seagull Energy Canada Ltd. ("Seagull") of assets at Rosebank.
November 1996	Acquisition of assets from Pensionfund Energy Resources Limited ("Pensionfund") of assets at Grande Prairie and Sibbald.
December 1996	Acquisition of assets from Seagull at Sundre. Acquisition of assets from Pensionfund at Countess-Leckie and Westerose.
March 1997	Acquisition of assets from Pensionfund at Countess.
April 1997	Corporate acquisition of Bayridge Resources Limited.
February 1998	Acquisition of assets from Pinnacle Resources Ltd. at Caroline
June 1998	Acquisition of assets from Harbour Petroleum Company Limited at Wayne-Rosedale.
August 1998	Acquisition of assets from Talisman Energy Inc. at Pembina, together with a sale of assets to Talisman at Grande Prairie and Sibbald.
September 1998	Acquisition of assets from limited partnerships managed by EnerVest Resource Management Ltd. at Gleneath, together with other minor assets.
February 1999	Acquisition of assets from Newport Petroleum Corporation at Countess.
February 1999	Acquisition of assets from Tethys Energy Inc. at Girouxville.
December 2000	Acquisition of assets from Grey Wolf Exploration Inc. at Redwater and sale to Grey Wolf of assets at Caroline.
April 2001	Corporate acquisition of Alliance Energy Inc.
April 2001	Acquisition of assets from third party in Southeast Saskatchewan.
August 2001	Acquisition of assets from a third party at Sakwatamau

The September, 1996, November, 1996 and December, 1996 transactions comprised oil and gas assets which formed the "Initial Properties", as defined in the Trust's final prospectus dated November 29, 1996 for its initial public offering. In addition to the foregoing, the Corporation has added reserves through optimization initiatives and drilling on its various properties, as well as through minor acquisitions.

The Corporation will continue to pursue both oil and gas asset and corporate acquisitions. These transactions will be financed through a combination of credit facilities, available working capital and the proceeds from future issues of trust units. The Manager's objectives are to: (1) acquire assets that will generate a high rate of return for Unitholders; (2) acquire assets with upside potential, where the value can be maximized through optimization, low-risk drilling and improvements to infrastructure; (3) seek opportunities to act as operator of the properties, which will allow the Corporation to control the timing and cost of optimization, drilling and maintenance initiatives; (4) manage risk through commodity, currency and interest rate hedging and oil & gas marketing strategies, to ensure that Unitholders receive above-average cash distributions; (5) keep administrative costs low by running an efficient management structure; (6) grow the Corporation to improve liquidity and create a more effective market in which investors of the Trust can buy or sell Trust Units.

Recent Developments

Equity Issue

On February 13, 2002, the Trust completed an equity offering of 3,250,000 trust units at $9.75 per trust unit for aggregate gross proceeds of $31,687,500, including the exercise of the underwriters' option. The syndicate of underwriters was led by Scotia Capital. The net proceeds of the issue were to be used to repay outstanding indebtedness, to fund future acquisitions and capital expenditures and for general corporate purposes.

Acquisition

On April 17, 2002, the Trust announced that it had entered into agreements to acquire the shares of two private corporations for total consideration of approximately $57.0 million consisting of Trust Units, warrants to acquire Trust Units, cash and assumption of debt. It is expected that the transactions will close in late May.

The Trust has agreed to purchase the shares of Kinwest Resources Inc. ("Kinwest"), a private corporation with approximately 120 shareholders, for $3.30 per share plus the assumption of $9.9 million of debt. With 6,670,843 shares outstanding, and assuming an election for maximum cash of $6.6 million, the Trust will issue a 1,518,192 Trust Units at $10.15 per Trust Unit. The total Kinwest transaction has an approximate value of $32 million.

Concurrently with the acquisition of the Kinwest shares, APF has agreed to acquire the interests of Kinwest's joint venture partner for approximately $25 million. The joint venture partner has an interest in substantially all of the assets owned by Kinwest, with Kinwest accounting for 56% of the total and the joint venture partner 44%. All of the assets were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") in an independent report effective October 1, 2001 (the "GLJ Report"). The purchase price for the shares of the joint venture partner will be satisfied by the issuance of 1,283,538 Trust Units at a deemed price of $10.15 per Trust Unit, in the event the joint venture partner elects to take the maximum cash of $12.0 million.

In both transactions, those electing to receive Trust Units will also receive one-half warrant for each Trust Unit issued, entitling the holder of a full warrant to acquire one Trust Unit at a price of $10.65 during the one-year period following closing. The warrants will not be listed on any stock exchange.

The assets to be acquired by APF include interests in Southeast Saskatchewan at Macoun, Handsworth, Workman and Alameda and are all proximate to existing APF operations. The acquisition will increase APF's total daily production from approximately 7,000 boe to over 9,000 boe.

The boards of directors of APF, Kinwest and the joint venture partner have approved the proposed transactions, and the board of directors of Kinwest has resolved unanimously to recommend to its shareholders that they accept the APF offer. The Kinwest transaction is being completed by way of plan of arrangement and Kinwest anticipates forwarding an information circular to its shareholders on or about May 3, 2002. The transactions are subject to regulatory approval.

The officers and directors of Kinwest have agreed to execute lock-up agreements representing at least 21% of the fully-diluted outstanding shares of Kinwest under which they will agree to deposit and not withdraw their shares under the offer. The board of directors of Kinwest has also agreed that it will not solicit or initiate discussions or negotiations with any third party for any business combination involving Kinwest.

The cash portion of the transaction of up to $18.6 million will be funded by APF's available credit facilities and together with APF's capital program for the balance of 2002 would fully utilize the proceeds raised by APF in the $32 million equity issue it completed on February 13, 2002.

BUSINESS AND PROPERTIES OF THE CORPORATION

Principal Producing Properties

The Properties of the Corporation on which the Royalty has been granted include both unitized and non-unitized oil and natural gas production. The Properties contain long life reserves. Of the present value of the estimated future net cash flow from the Properties, approximately 84% is located in 4 core areas as outlined in the table below:

Properties	Average % Interest (1)	Company Interest Reserves (2)(3)	Estimated Net 2002 Production (4)(6)	Asset Value (3)(6)	
		(mboe)	(boe/d)	($000's)	(%)
Southeast Sask.	57	8,490	3,609	51,390	35
Countess	82	5,082	1,615	41,305	28
Pembina	5	3,652	578	18,236	13
Redwater	62	1,367	692	12,013	8
Other Properties		3,451	1,148	23,477	16
TOTAL		22,042	7,642	146,421	100

Notes:

(1) The percentage company interest owned by the Corporation in the Properties is based on its share of Established Reserves (Proved Reserves plus 50% of Probable Reserves, as defined below), including working interest and overriding royalty interest.
(2) The company interest share of recoverable reserves before the deduction of royalties.
(3) Based on Established Reserves outlined in the Gilbert Report. See "Oil and Natural Gas Reserves".
(4) Reserve life is the time remaining during which production is forecast to be economic.
(5) Discounted at 12% and based on the escalated price and cost forecast contained in the Gilbert Report. ARC is included, where applicable.
(6) The average production rate for 2002 as outlined in the Gilbert Report.

Southeast Saskatchewan

APF acquired approximately 3,600 bbls per day of production in the southeast Saskatchewan area during Q2- 2001 with an average working interest of 57 percent in 357 producing oil wells. APF operates most of this production and has ownership in the infrastructure in each of the major areas. Most of APF's oil pools receive pressure support from a regional acquifer. Development during recent years has primarily been through the drilling of horizontal wells. During 2001, APF drilled eight (5.1 net) horizontal wells and initiated two 3D seismic programs. Plans for 2002 include drilling in excess of 15 horizontal wells. Production for the year is forecast to be 3,570 bbls per day. APF's three major producing areas in the region include Tatagwa, Queensdale and Carlyle. At Tatagwa, APF has an average 76 percent working interest in 46 producing oil wells for net oil production of 900 bbls per day during 2002. Production is from both the Marly and Vuggy zones of the Midale Formation. APF also holds an 80 percent working interest in the central oil battery and water disposal facility and receives processing income from third parties using the facility. During 2001, APF drilled two (1.6 net) horizontal oil wells and will conduct additional drilling during 2002. APF holds an average working interest of 68 percent in 48 oil wells at Queensdale. Net production for 2002 is expected to be 948 bbls per day from the Frobisher-Alida zone. APF also has ownership in three central batteries and water disposal facilities in the area. During 2001, APF drilled three (1.8 net) horizontal oil wells. Drilling in the area will continue following an interpretation of a 3D seismic program shot during Q1-2002. The Carlyle property is forecast to produce 342 bbls per day (net) from nine oil wells at an average working interest of 89 percent. One horizontal oil well was drilled into the Alida zone during 2001 (0.9 net) and will be followed by additional drilling during 2002. A 3D seismic program has been shot in the area during Q1-2002 that will identify further horizontal drilling opportunities. APF also holds a 90 percent working interest in a central battery and water disposal facility at the property.

Countess, Alberta

The Countess area in southeast Alberta, which is comprised of both the Countess and Leckie properties, contributes production from a total of 346 natural gas wells. Dry natural gas is produced from the shallow sands of the Belly River, Milk River and Medicine Hat formations. The gas is gathered, dehydrated, and compressed in the field and sold under a long-term contract to TransCanada Gas Services. In addition, APF receives custom compression revenue from surplus capacity in two 720-horsepower compressors. APF has an average working interest of 75.2 percent in 24,960 acres of land at Countess. During 2001, APF drilled 10 wells on 80-acre spacing. The program produced very positive results and APF plans to drill another 10-20 wells on 100 percent working interest lands during 2002. Production is expected to average 4,979 mcf per day for the year. At Leckie, APF has a 100 percent working interest in 22,880 acres of land and a 100 percent interest in a compressor station. In 2001, APF drilled 20 wells on 80-acre spacing that targeted the Milk River and Medicine Hat formations. Plans for 2002 include drilling another 10 wells. During 2002, production is expected to average 4,708 mcf per day.

Pembina, Alberta

APF has interests in five Pembina Cardium units located approximately 116 kilometres southwest of Edmonton, including 100 percent working interests and operatorship of Champlin-Peruvian Cardium Unit No. 1 and Pembina Cardium Unit No. 20. APF holds non-operated working interests of 7.35 percent in Pembina Cardium Unit No. 12, 5.15 percent in Pembina Cardium Unit No. 9 and 1.26 percent in North Pembina Cardium Unit No. 1. Light crude oil is produced from 581 wells under waterflood programs in the Cardium formation in each of the units. Oil is treated at batteries associated with each unit and solution gas is gathered and processed through APF's share of the Pembalta gathering system. During 2001, APF participated in the drilling of 28 (3.4 net) wells, all of which were completed as successful Cardium oil wells. Several more wells will be drilled during 2002 and production is expected to average 578 bbls per day.

Redwater, Alberta

The Redwater area is located northeast of Edmonton, Alberta. Dry natural gas is produced from a combination of the Wabamun, Detrital, Basal Quartz, Glauconitic, Colony, Second White Specs and Sparky zones. The production is sold under a combination of short and long-term gas contracts, as well as the spot market. APF has an average 62 percent working interest in 59 producing wells that cover approximately 167 sections of land. During 2001, APF recompleted five wells and drilled six (3.4 net) wells, resulting in 1.3 net gas wells and 0.1 net suspended wells. APF acquired 17 sections of land at Crown land sales during the year. Plans for 2002 include drilling five wells and the recompletion of seven wells. Production during 2002 is expected to average 4,151 mcf per day.

Facilities

The following table sets out major facilities in which the Corporation has an interest. Information presented is at January 1, 2002.

Area Name	Major Facilities[1]
S.E. Saskatchewan	Various working interests in batteries.
Countess, Alberta	42% interest in the Countess natural gas plant; 100% interest in the Countess-Leckie compressor and 4 booster compressors.
Redwater, Alberta	Interests in natural gas facilities as follows: 90% Radway compression 50% Redwater 8-9 compression and dehydration 50% Redwater 13-27 compression and dehydration
Pembina, Alberta	Interests in unit oil treating and water injection facilities as follows: 1.26% North Pembina Cardium Unit 7.35% Pembina Cardium Unit No. 12 100% Pembina Cardium Unit No. 20 5.15% Pembina Cardium Unit 9 65.78% Champlin-Peruvian Cardium Unit Interests in natural gas processing facilities as follows: 0.52% Pembalta No. 1 0.66% Pembalta No. 2 1.10% Pembalta No. 3 2.66% Pembalta No. 4 0.10% Pembalta No. 5 1.21% Pembalta No. 7 0.47% Pembalta No. 8

Note:

(1) "Major Facilities" includes only significant processing facilities and pipelines associated with the designated area.

Oil and Natural Gas Reserves

Gilbert Laustsen Jung Associates Ltd. ("Gilbert"), independent petroleum consultants, prepared a report (the "Gilbert Report") on the reserves attributable to the Properties and the present value of the estimated future net cash flow associated with such reserves effective January 1, 2002.

The following tables set forth certain information relating to the oil and natural gas reserves of the Properties, and the present value of the estimated future net cash flow associated with such reserves, as derived from the Gilbert Report. **All evaluations of future net cash flow in the Gilbert Report are after deduction of estimated future capital expenditures, royalty burdens, operating expenses and well abandonment costs and prior to any provision for income taxes, debt service charges, management fees and general and administrative costs. It should not be assumed that the present value of estimated future net cash flow shown below is representative of the fair market value of the Properties. There is no assurance that the escalated cost and price assumptions contained in the Gilbert Report will be attained. In the Established Reserves case, Probable Reserves and related cash flows have been reduced by 50% to reflect the risk of recovery.**

Oil and Natural Gas Reserves
and Present Values
Escalated Cost and Price Assumptions
(columns may not add due to rounding)

	Working Interest Reserves						Present Value of Estimated Future Net Cash Flow at Discount Rate of[3]			
	Gross[1]			Net[2]						
	Oil (Mbbl)	Gas (Mmcf)	NGL (Mbbl)	Oil (Mbbl)	Gas (Mmcf)	NGL (Mbbl)	0%	10%	15%	20%
							($000)			
Proved										
Producing[4][5]	10,473	39,361	441	9,077	31,916	319	217,079	129,016	109,975	96,645
Non-Producing[4][6]	785	4,780	41	656	3,853	29	22,724	13,595	11,281	9,545
Total Proved	11,258	44,141	482	9,733	35,769	348	239,803	142,611	121,256	106,190
Risked Probable[7]	1,762	6,843	43	1,524	5,554	32	39,803	15,256	11,170	8,629
Established	13,020	50,984	525	11,257	41,323	380	279,606	157,867	132,426	114,819

Oil and Natural Gas Reserves
and Present Values
Constant Cost and Price Assumptions
(columns may not add due to rounding)

	Working Interest Reserves						Present Value of Estimated Future Net Cash Flow at Discount Rate of[3]			
	Gross[1]			Net[2]						
	Oil (Mbbl)	Gas (Mmcf)	NGL (Mbbl)	Oil (Mbbl)	Gas (Mmcf)	NGL (Mbbl)	0%	10%	15%	20%
							($000)			
Proved										
Producing [4][5]	10,504	39,205	441	9,107	31,778	320	190,415	117,410	100,858	89,123
Non-Producing[4][6]	789	4,750	42	660	3,827	28	19,479	11,801	9,778	8,255
Total Proved	11,293	43,955	483	9,767	35,605	348	209,894	129,211	110,636	97,378
Risked Probable[7]	1,751	6,784	43	1,514	5,502	32	31,548	12,926	9,562	7,416
Established	13,044	50,739	526	11,281	41,107	380	241,442	142,137	120,198	104,794

Notes:

(1) "Gross Working Interest Reserves" means the working and overriding royalty interest share of remaining recoverable reserves before deduction of royalties.

(2) "Net Working Interest Reserves" are Gross Working Interest Reserves less all lessor and overriding royalties and interests owned by others.

(3) The net cumulative cash flow forecasts are after direct lifting costs, royalties, mineral taxes and future capital investments but before general and administrative expenses, management fees, debt service charges and income taxes. Well abandonment and site restoration costs were included in the cash flow and net present value estimates as well as Alberta natural gas cost allowance and Jumping Pound allowances on remaining undepreciated capital bases and income from custom processing fees. ARC has been included, where applicable.

(4) "Proved Reserves" are those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions in the case of constant price and cost analyses and anticipated economic conditions in the case of escalated price and cost analyses, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(5) "Producing Reserves" are those reserves that are actually on production and could be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a small investment relative to cash flow. In multi-well pools involving a competitive situation, reserves may be subdivided into producing and non-producing reserves in order to reflect allocation of reserves to specific wells and their respective development status.

(6) "Non-Producing Reserves" are those reserves that are not classified as producing.

(7) "Probable Reserves" are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggests the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above

that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(8) The pricing assumptions used in the Gilbert Report with respect to the cumulative net cash flow (escalated) as well as the inflation rates used for operating costs are set forth below:

Year	Exchange Rate $US/Cdn	W.T.I. Crude Oil at Cushing Oklahoma Then Current $US/Bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/Bbl	Alberta NGLs (Then Current Dollars) Spec Ethane $Cdn/Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Pentanes Plus $Cdn/Bbl
2002	0.635	20.00	30.75	13.75	19.75	20.75	31.75
2003	0.650	21.00	31.25	15.25	20.25	21.25	32.25
2004	0.670	21.00	30.50	15.50	19.50	20.50	31.50
2005	0.690	21.00	29.50	15.75	18.50	19.50	30.00
2006	0.700	21.25	29.50	15.75	18.50	19.50	30.00
2007	0.700	21.75	30.00	15.75	19.00	20.00	30.50
2008	0.700	22.00	30.50	15.75	19.50	20.50	31.00
2009	0.700	22.25	31.00	15.75	19.75	21.00	31.50
2010	0.700	22.50	31.50	16.00	20.25	21.50	32.00
2011	0.700	23.00	32.00	16.25	20.50	22.00	32.50
2012	0.700	23.25	32.50	16.50	20.75	22.50	33.00
2013+	0.700	------------------------------------- Escalate at 1.5% per year -------------------------------------					

Year	AECO-C Spot Then Current $Cdn/Mmbtu	Alberta Plant Gate Average Then Current $Cdn/Mmbtu	Spot(b) $Cdn/Mmbtu	Aggregator $Cdn/Mmbtu	Alliance $Cdn/Mmbtu
2002 Full Year	4.30	3.95	4.10	3.60	3.55
2003	4.65	4.35	4.45	4.15	4.00
2004	4.70	4.45	4.50	4.35	4.05
2005	4.70	4.50	4.50	4.50	4.00
2006	4.70	4.50	4.50	4.50	4.05
2007	4.70	4.50	4.50	4.50	4.10
2008	4.70	4.50	4.50	4.50	4.15
2009	4.75	4.55	4.55	4.55	4.25
2010	4.80	4.60	4.60	4.60	4.35
2011	4.90	4.70	4.70	4.70	4.40
2012	4.95	4.75	4.75	4.75	4.45
2013+	---------------------------------- Escalate at 1.5% per year ----------------------------------				

Comments respecting pricing assumptions:

a) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system, known as the plant gate. The plant gate price represents the price before raw gas gathering and processing charges are deducted.

b) Spot refers to weighted average one month price.

(9) Operating and capital costs were escalated from 2002 base levels at a rate of 1.5% per year.

(10) For constant price evaluations, the Gilbert Report used a base oil price of $30.75 per Bbl of light sweet crude oil and an average Alberta natural gas price of $3.95 per Mmbtu of natural gas.

(11) The Gilbert Report has estimated total capital costs of $13,541,000 (undiscounted) in order to achieve the future net cash flow from Established Reserves in the escalated price case.

(12) In both the escalated and the constant price cases, the Gilbert Report adjusted the base product prices to reflect property specific factors: for example crude quality differentials, natural gas BTU content, transportation tariffs and the details of product sales contracts.

(13) All of the Proved Producing Reserves are currently on production.

Reconciliation of Reserves

The following table contains management's reconciliation of the Established Reserves of the Corporation, as set out in the Gilbert Report, to Established Reserves as at the year ended December 31, 2001.

	Oil (Mbbl)	Gas (Bcf)	NGLs (Mbbl)	Total (MBOE)(1)
Reserves at December 31, 2000	5,212	46.4	436	13,375
Acquisitions	7,747	4.7	157	8,687
Drilling and Development	1,510	5.1	9	2,369
Divestitures	(509)	(0.7)	(19)	(645)
Production	(1,071)	(5.7)	(43)	(2,064)
Revisions	130	1.0	(15)	282
Reserves per Gilbert Report	13,020	51.0	525	22,042

Notes:

(1) Oil equivalent volumes are based on a gas/oil conversion ratio of 6:1.
(2) Columns may not add due to rounding.

Historic Operational Data – Last Eight Quarters

	Three Months Ended (unaudited)							
	December 31		September 30		June 30		March 31	
	2001	2000	2001	2000	2001	2000	2001	2000
Avg. production (pre royalty)								
Oil (bbl/d)	4,484	1,109	3,838	1,230	3,265	1,131	1,035	1,139
NGLs (bbl/d)	144	198	112	296	36	258	110	261
Gas (mcf/d)	16,523	14,057	15,351	12,763	15,022	13,539	14,647	13,437
Total (boe/d)	7,382	3,650	6,509	3,655	5,805	3,646	3,586	3,640
Avg net prices (pre hedging)								
Oil /$bbl	25.11	46.64	33.91	44.04	37.71	40.19	39.49	38.60
NGL/$bbl	15.76	47.93	31.47	35.56	35.32	31.52	49.43	31.64
Gas/$mcf	2.70	7.66	3.33	5.06	5.77	3.99	9.71	2.70
Average/$boe	21.60	46.27	28.39	35.35	36.36	29.52	52.57	24.32
Royalties ($000)	3,132	2,624	3,099	2,443	3,669	1,939	3,463	1,524
Oil/$bbl	5.43	8.98	6.13	8.72	7.07	8.21	6.42	7.12
NGL/$bbl	5.23	2.08	7.35	0.49	10.27	1.49	14.83	1.82
Gas/$mcf	0.54	1.25	0.61	1.40	1.12	0.86	2.07	1.45
Operating Expenses ($000)(1)	4,299	1,903	3,769	2,202	3,007	1,958	2,011	1,958
$/boe	6.33	5.67	6.29	6.55	5.69	5.90	6.23	5.91
Netbacks ($000)	9,127	10,753	11,448	6,909	12,338	5,916	10,562	4,847
$/boe	13.44	32.02	19.12	20.54	23.36	17.83	32.72	14.63
Expenditures ($000)								
Property acquisitions/ (Dispositions)	(3,707)	856	3,828	----	98,693	----	----	----
Development(2)	7,806	1,094	3,521	2,328	3,832	1,672	1,065	599

Notes:

(1) Operating expenses include all costs (exclusive of drilling costs, completion costs and equipping costs) to operate wells for the recovery of petroleum, freehold mineral, municipal and property taxes and surface lease rentals, but do not include general and administrative expenses or management fees.
(2) Including expenditures on facilities.

Drilling History

The following table sets forth the drilling activity for the Corporation for the periods indicated.

	Years Ended December 31					
	2001		2000		1999	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Oil	40	8.9	33	3.2	17	1.0
Natural Gas	33	31.4	65	14.8	6	6.0
Dry Wells	2	2.0	-		14	0.1
Other	1	0.1	27	0.5	38	0.7
TOTAL	76	42.2	125	18.54	75	7.8

Notes:

(1) "Gross" wells means the number of wells in which the Corporation has an interest.
(2) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest of the Corporation therein.

Capital Expenditures

The following table summarizes the Corporation's capital expenditures for the Properties for the periods indicated.

	Years Ended December 31		
	2001	2000	1999
Property Acquisition	$105,717,382	$13,248,833	$ 3,895,223
Land Acquisition	239,443	146,522	143,297
Seismic	207,596	15,292	98,572
Drilling and Completion	12,490,233	3,912,099	2,231,638
Production Facilities	3,339,714	1,618,772	949,749
Other	(52,148)	---	5,480
SUBTOTAL	121,942,220	18,941,518	7,323,959
Dispositions (including swaps)	(6,903,199)	(12,392,879)	(2,326,397)
NET CAPITAL EXPENDITURES	115,039,021	$6,548,639	$4,997,562

Producing Wells

The number of wells on the principal Properties in which the Corporation has an interest as at January 1, 2002 and which it considers capable of production are set out in the following table:

	Producing[(1)(6)]				Shut-in[(2)]				Other[(5)]	
	Oil		Gas		Oil		Gas			
	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]	Gross[(3)]	Net[(4)]
S.E. Sask.	347	161	----	----	21	7	----	----	25	14
Countess	----	----	346	301	----	----	9	9	----	----
Pembina	564	36	----	----	1	1	----	----	218	15
Redwater	----	----	86	47	----	----	10	5	----	----
TOTAL	801	187	432	348	16	7	19	14	236	28

Notes:

(1) Information provided by the Corporation which includes changes on the properties since the Gilbert Report.
(2) **"Shut-in"** wells means wells which are not producing but which the Corporation considers to be capable of production.
(3) **"Gross"** wells means the number of wells on the Properties in which the Corporation has an interest.
(4) **"Net"** wells means the number of gross wells multiplied by the net working interest share of the Corporation therein.
(5) **"Other"** wells include injection wells, disposal wells and service wells.
(6) All wells that are assigned Proved Non-Producing Reserves are within economic distance of gathering systems, pipelines or other means of transportation.

Undrilled Acreage.

APF Energy hold interests in a total of 109,513 net acres. These interests were evaluated by GLJ effective January 1, 2002 and were assigned a value of $4.9 million.

	Gross	Net
Alberta	93,068	48,559
Saskatchewan	148,794	60,585
Manitoba	930	369
Total	242,792	109,513

Marketing Arrangements

The Corporation's production mix was approximately 37% natural gas and 63% oil and NGL, based on average production during the fourth quarter of 2001. Except for Redwater, where gas is predominantly sold on the spot market or into short-term contracts, the balance of gas production (approximately 60%) is sold to aggregators pursuant to long-term contracts. The forecasted prices are set forth above, at "Oil and Natural Gas Reserves", at Note 8, relating to pricing assumptions. During 2001, the Corporation received an average of $4.98 per mcf for its natural gas, after hedging. The Corporation's oil and NGL were sold on a combination of short-term and spot contracts, which averaged $33.64 and $30.97 per bbl, respectively, after hedging.

Future Commitments

The Corporation had the following hedges in place as of April 26, 2002:

	Oil		Gas	
	Volume (bbl/d)	Price US$/bbl	Volume (mcf/d)	Price (C$/mcf)
January 2002	2,000	27.38	2,625	3.94-4.78
February 2002	2,000	24.00	2,625	3.94-4.78
March 2002	2,000	23.85	2,625	3.94-4.78
April 2002	2,000	21.38	2,100	4.20-5.51
May 2002	3,000	22.39	2,100	4.20-5.51
June 2002	3,000	20.92	2,100	4.20-5.51
July 2002	3,000	20.95	2,100	4.20-5.80
August 2002	2,000	22.11	2,100	4.20-5.80
September 2002	1,500	22.64	2,100	4.20-5.80
October 2002	1,000	24.46	2,100	4.20-7.06
November 2002	1,000	24.55	2,100	4.20-7.06
December 2002	1,000	24.42	2,100	4.20-7.06
January 2003	----	----	2,100	4.20-8.22
February 2003	----	----	2,100	4.20-8.22
March 2003	----	----	2,100	4.20-8.22

DIRECTORS AND OFFICERS

The Trust has no directors and officers. The following information pertains to the board of directors and the officers of the Corporation and of the Manager.

The Corporation

The name, municipality of residence, position held and principal occupation of each director and officer of the Corporation are as set forth below:

Name and Municipality of Residence	Position with the Corporation	Principal Occupation
Donald Engle, P. Land[(1)(2)(4)] Calgary, Alberta	Director and Chairman of the Board	President of Sapphire Resources Ltd., an oil and gas consulting company
William Kenneth Dickson[(1)(2)] Calgary, Alberta	Director	Director of Dickson Resources Inc., an oil and gas company
Daniel Mercier[(1)(4)] Okotoks, Alberta	Director	Vice President, Operations, SOCO International plc, an international oil and natural gas exploration company
Martin Hislop, C.A.[(2)(3)] Calgary, Alberta	Director, President and Chief Executive Officer	President and Chief Executive Officer of the Manager and the Corporation
Steven G. Cloutier, LL.B.[(3)(4)] Calgary, Alberta	Director, Executive Vice-President, Chief Operating Officer, Secretary and Treasurer	Executive Vice-President and Chief Operating Officer of the Manager and the Corporation
Bonnie Nicol, P.Eng. Calgary, Alberta	Vice-President, Operations	Vice-President, Operations of the Manager and the Corporation
R. Kenneth Pretty, P.Land Calgary, Alberta	Vice-President, Corporate Development and Land	Vice-President, Corporate Development and Land of the Manager and the Corporation
Alan MacDonald, C.A. Calgary, Alberta	Vice-President, Finance	Vice-President, Finance of the Manager and the Corporation

Notes:

(1) Independent directors who have been elected to represent the Unitholders until the next annual general meeting of the Corporation. In Mr. Engle's case, his appointment became effective December 1, 2000. All other directors have held the offices indicated since the formation of the Trust.
(2) Member of the Audit Committee
(3) Nominee of the Manager.
(4) Member of the Compensation Committee. Currently, the full Board sits as a Reserves Committee.

Each of the directors and officers of the Corporation has held the same principal occupation for the past five years except as described below.

Mr. Engle is a professional Landman and has been President of Sapphire Resources Ltd., a private oil and gas consulting company, since 1985. From 1996 to May, 2000, Mr. Engle was also President of Grey Wolf Exploration Inc., a publicly traded oil and gas company listed on the The Toronto Stock Exchange. He is also on the Board of the CDNX Listed Companies Association.

Mr. Dickson is a consultant, and has provided oilfield operations advice to oil and natural gas service companies since 1989, upon retirement as Vice President, Production of Ultramar Oil and Gas Canada Ltd. During that time, he has also been a director of Dickson Resources Inc., an oil and natural gas company and of Arlyn Enterprises Ltd., a vendor of commercial and consumer lubrication oils. From November, 1995 to January, 1997, he was Vice-President of 3-D Reclamation Inc., a company carrying on the business of abandoning and related reclamation of oil and natural gas wells.

Mr. Mercier is Vice President, Operations for SOCO International plc ("SOCO"), a position he accepted in September, 1998. Prior thereto he was Chairman, Chief Executive Officer and a director of Territorial Resources, Inc., a Colorado company engaged in international oil and natural gas exploration which merged with SOCO on September 8, 1998. SOCO is a publicly traded United Kingdom corporation engaged in international oil and natural gas exploration and production.

Martin Hislop has had the same principal occupation with the Manager since September of 1994 and became an officer of the Corporation in December, 1995. From 1986 to July of 1994, Mr. Hislop was President and Chief Executive Officer of Lakewood Energy Inc. and its predecessor, Lakewood Capital Group Inc.

Steven Cloutier has had the same principal occupation with the Manager since September of 1994 and became an officer of the Corporation in December, 1995. From 1991 to October 1994, Mr. Cloutier was in private law practice.

Ms. Nicol joined the Corporation and the Manager in January, 1998. From February, 1997 to January, 1998, she was Manager, Saskatchewan and Provost Business Unit with Northstar Energy Corporation. She was Senior Exploration Engineer with Northstar from August, 1995 to January, 1997. From 1993 to 1995, she was Senior Petroleum Engineer with Northridge Exploration Inc. and prior thereto was a petroleum engineer with Chevron Canada Resources Limited.

Mr. Pretty joined the Corporation and the Manager in March, 2001. From June, 2000 to March, 2001, he was Vice-President, Land and Business Development with Hunt Oil Company of Canada, and from March, 1998 to June, 2000 was Vice-President of Land with Newport Petroleum Corporation until it was acquired by Hunt Oil Company of Canada. From April, 1996 to March, 1998 he was employed at Petro-Canada as a staff landman and prior thereto was a senior landman at Amerada Hess Canada and Norcen Energy Resources Ltd.

Mr. MacDonald joined the Corporation and the Manager in August, 2001. From April 1999 to June 2001, he was Vice-President, Finance with Due West Resources Inc., and from 1987 to 1999 was Vice-President, Finance with Starvest Capital Inc.

The Corporation currently has a board of directors consisting of five individuals, three of whom are independent directors elected by the Unitholders and two of whom are elected by the Manager. The Chairman of the board of directors must be one of the independent directors and that office is currently filled by Donald Engle.

As at December 31, 2001, the manager and the directors and senior officers of the Corporation, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, approximately 2.3% of the total outstanding Trust Units (approximately 6.5% after the exercise of options pursuant to the Trust's Trust Unit incentive plan).

The Manager

The name, municipality of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Municipality of Residence	Position with the Manager	Principal Occupation
Martin Hislop, C.A. Calgary, Alberta	Chairman of the Board of Directors, President and Chief Executive Officer	President and Chief Executive Officer of the Manager and the Corporation
Steven G. Cloutier, LL.B. Calgary, Alberta	Executive Vice-President, Chief Operating Officer, Director, Secretary and Treasurer	Executive Vice-President and Chief Operating Officer of the Manager and the Corporation
Bonnie Nicol, P.Eng. Calgary, Alberta	Vice-President, Operations	Vice-President, Operations of the Manager and the Corporation
R. Kenneth Pretty Calgary, Alberta	Vice-President, Corporate Development and Land	Vice-President, Corporate Development and Land of the Manager and the Corporation
Alan MacDonald, C.A. Calgary, Alberta	Vice-President, Finance	Vice-President, Finance of the Manager and the Corporation

Conflicts of Interest

There may be situations in which the interests of management of the Trust will conflict with those of the Unitholders. Management of the Trust owns oil and natural gas properties that do not form part of the Properties held by the Corporation. Management of the Trust may also acquire interests in energy-related businesses on its own account and on behalf of persons other than the Unitholders. Management of the Trust manages and administers such additional properties and may enter into other types of energy-related management and advisory activities. Thus, management of the Trust will carry on their full time activities on behalf of the

Unitholders and, when acting on behalf of others, may at times act in contradiction to or in competition with the interests of the Unitholders.

In resolving such conflicts, decisions will be made on a basis consistent with the objectives and funds of each group of interested parties and the time limitations on investment of such funds, all consistent with the duty of such management to deal fairly and in good faith with each such group of persons. The APF Energy Management Agreement contains provisions which require the Manager to make disclosure to the board of directors of the Corporation of the fact and substances of any particular conflict of interest and to use all reasonable efforts to resolve those conflicts of interest in a manner which will treat the Trust or the Corporation, as the case may be, and the other interested party fairly, taking into account all of the circumstances of the Trust or the Corporation, as the case may be, and that interested party and to act honestly and in good faith in resolving such matters.

All conflicts among officers and directors of the Corporation will be resolved in accordance with the provisions of applicable legislation.

Oil and natural gas properties may occasionally be made available for purchase in areas where management of the Corporation or their other clients hold interests. In such circumstances, management shall provide each of its clients, including the Corporation and any subsidiaries of the Corporation or the Trust, with the opportunity to participate in the acquisition of such properties in the proportion that each of its clients has funds available for such acquisition.

Properties will not be acquired from officers or directors of the Manager or other managers, or persons not at arm's length with such persons, at prices which are greater than fair market value, nor will properties be sold to such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor or independent engineering firm and approved by the independent members of the board of directors of the Corporation.

Circumstances may arise where members of the board of directors of the Corporation serve as directors or officers of corporations which are in competition to the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

SELECT CONSOLIDATED FINANCIAL INFORMATION

Following is certain consolidated financial data for the Corporation and the Trust for the periods noted.

	Twelve Months Ended December 31		
	2001	2000	1999
Revenues (Net of Royalties - $000)	56,561	36,445	20,809
Expenses ($000)	43,241	20,774	25,498
Future income taxes ($000)	(5,174)	1,406	----
Minority interest ($000)	349	190	133
Net income (loss) after unusual items ($000)	18,144	14,075	(4,822)
/trust unit ($)	1.44	2.04	(0.82)
/trust unit (diluted - $)	1.44	2.04	(0.82)
Cash distributions ($000)	37,311	13,899	9,188
Total assets ($000)	198,176	67,388	63,843
Long-term debt ($000)	59,250	25,736	33,171

	Three Months Ended (unaudited)							
	2001				2000			
	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31
Revenues (Net of Royalties - $000)	13,426	15,217	15,345	12,573	12,656	9,110	7,874	6,804
Expenses ($000)	14,457	12,385	11,141	5,258	5,200	5,365	5,058	5,151
Future income taxes ($000)	(1,775)	(1,459)	(1,339)	(600)	2,100	(394)	(300)	----
Minority interest ($000)	11	132	95	111	16	73	66	36
Net income after unusual items ($000)	733	4,159	5,448	7,804	5,341	4,068	3,050	1,617
/trust unit ($)	0.05	0.29	0.49	0.95	0.75	0.57	0.43	0.26
/trust unit (diluted - $)	0.05	0.29	0.49	0.95	0.75	0.57	0.43	0.26
Cash distributions ($000)	8,571	11,602	11,204	5,933	5,278	3,450	2,809	2,362
Total assets ($000)	198,176	200,705	200,189	88,793	67,388	63,913	63,900	62,037
Long-term debt ($000)	59,250	59,750	48,645	13,286	25,736	23,909	24,139	23,794

MANAGEMENT'S DISCUSSION OF VARIATION IN OPERATING RESULTS

Reference is made to the information under the heading "Management's Discussion and Analysis" in the Annual Report, which information is hereby incorporated by reference into this Annual Information Form.

COMPETITIVE MATTERS

The Trust's cash distributions are dependent on a number of factors, including the underlying commodity prices and production of the Corporation's oil and gas assets. To a large extent, the price of the Trust Units is in turn reflective of the quantum of the Trust's cash distributions.

In order to replace and add production, the Corporation must be able to acquire oil and gas assets on favourable terms. Moreover, the Trust must be able, from time to time, to access the equity markets in order to provide the Corporation with the capital required to make acquisitions.

The acquisitions' market is extremely competitive, both with respect to corporate transactions as well as to asset purchases. In addition to competition from other income trusts, the Trust and the Corporation must compete with oil and gas companies for the same opportunities. These competitors may have different financial strength than the Trust or the Corporation which may put them in a superior position.

ENVIRONMENTAL MATTERS

The Corporation carries out its activities in compliance with all relevant provincial and federal regulations and good industry practice.

The Corporation has an Environmental and Safety Committee comprised of the Chief Operating Officer, Vice President, Operations and Production Manager. This Committee reports directly to the Corporation's Board of Directors, which reviews environmental matters related to the Corporation's business.

At present, the Corporation believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. Since these requirements apply to all operators in the oil and natural gas industry, it is not anticipated that the Corporation's competitive position within the industry will be adversely affected. The Corporation's major production facilities are relatively new and the likelihood of major capital expenditures being required to meet future changes is reduced in the near term. The Corporation has internal procedures designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding with them.

Commission
des valeurs mobilières
du Québec

Marché des capitaux

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DÉCISION N° : 2002-MC-1521

NUMÉRO DE PROJET SÉDAR: 443432

DOSSIER N° : 13904

Objet : APF Energy Trust
Demande de dispense de prospectus et de l'inscription

Vu la demande présentée le 6 mai 2002;

vu les articles 11, 148 et 263 de la Loi sur les valeurs mobilières;

vu les pouvoirs délégués conformément à l'article 307 de la Loi.

En conséquence, le directeur des marchés des capitaux :

> dispense APF Energy Trust de l'obligation d'établir un prospectus et de l'inscription à titre de courtier concernant le placement de 2 493 968 parts de fiducie et 1 246 984 bons de souscription de parts de fiducie auprès des actionnaires de Kinwest Resources Inc. en échange de leurs titres dans le cadre d'un regroupement de sociétés, conformément aux informations déposées auprès de la Commission
>
> dispense APF Energy Trust de l'obligation d'établir un prospectus et de l'inscription à titre de courtier concernant le placement de 7 670 843 droits de souscription de 981 647 Alberta Ltd.

Fait à Montréal, le 17 mai 2002.

Le directeur des marchés des capitaux,

(s) Jean-François Bernier
Jean-François Bernier

LAU/lb