

NORTHLAND POWER INCOME FUND

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focused on

Annual Report 2001



**NORTHLAND POWER
INCOME FUND**

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Highlights

Years ended December 31	2001	2000
Production		
Electricity (MWh)	739,701	739,687
Steam (ooo lb.)	1,012,015	997,164
Financial (\$ooo)		
Sales	68,411	61,576
Net income	20,640	18,965
Funds from operations before working capital changes	30,978	29,194
Cash available for distribution	31,951	23,116
Distributions declared to unitholders (\$ooo)	30,207	28,974
Distributions per unit	\$0.98	\$0.94

Distributions at \$0.98 were above the forecast in last year's annual report and the \$0.94 per unit achieved in 2000.

Electricity sales revenue was 8% higher than the prior year as a result of an increase in electricity prices under the long-term power purchase agreement.

Plant employees continued their exemplary safety record; there have been no lost-time injuries since plant start-up in September 1996.

The plant continues to meet all Ministry of Environment requirements and standards.

The Fund's **Distribution Reinvestment Plan** came into effect on July 1, 2001. Visit NPIFund.com for further details.

The Fund maintains its stability rating of SR-2 from Standard & Poor's, which denotes a very high level of stability in distributions.

NORTHLAND POWER INCOME FUND (the “Fund”) is a trust that, directly and through its wholly-owned

After five successful years, prudence continues to be our watchword in all aspects of managing your

subsidiary, Iroquois Falls Power Corp., owns a 110 MW cogeneration power plant located in Iroquois Falls,

asset to protect your investment.

Ontario (the “Facility”). The Facility supplies electricity to Ontario Electricity Financial Corporation

The Fund's financial results speak for themselves. Unit value increased by 31% in the past 12 months,

(as successor to Ontario Hydro) and steam to the neighbouring Abitibi-Consolidated Company of Canada pulp

distributions of 98 cents per unit are four cents more than forecast and revenue from sales is up 11%.

and paper mill. The electricity and steam are sold and natural gas is purchased under long-term contracts that

We carefully examined a number of growth and expansion opportunities in 2001. None met our

reduce the Fund's exposure to unexpected price and volume fluctuations and provide predictable cash flow.

criteria: that they increase distributions per unit on a sustained basis while not adversely affecting the Fund's

The Fund is administered and the Facility is managed by Iroquois Falls Power Management Inc., a wholly-

risk profile. We continue to seek out

owned subsidiary of Northland Power Inc., which is a

investments that are the right fit.

leading Canadian independent power company with extensive experience in all aspects of private power

Careful stewardship also extends to our people and the environment. High employee retention and

development and operational management.

ongoing training ensure maximum plant availability. And our efficient cogeneration plant minimizes the

As at March 7, 2002, the Fund had 30,823,443 trust units outstanding, which trade on The Toronto Stock

environmental impact on the world around us.

Exchange under the symbol NPI.UN. The units are qualified investments under the Canadian Income Tax Act

for RRSPs and DPSPs and are not considered foreign property for such plans.

stewardship

**Letter to
Unitholders**

I am pleased to report that Northland Power Income Fund had another successful year in 2001. As a result of higher selling prices for electricity, we were able to increase distributions to unitholders to \$0.98 per unit from \$0.94 last year.

The Fund's strategy of having up to 90% of its revenues and about 80% of its costs underpinned by long-term contracts was substantiated again this year, as the sudden and unexpected rise in the market price of natural gas that began in 2000 continued into the early part of 2001. The Fund was shielded entirely from this as we have 100% of our gas requirements supplied under long-term contracts. In fact, we achieved some benefit as we received high market prices for the gas that we regularly resell to offset fixed transportation costs on the TransCanada PipeLines Limited system at times that we aren't using our full contracted pipeline entitlement.

The Fund also benefited from a significant increase in electricity prices under our long-term power purchase agreement when Ontario Electricity Financial Corporation ("OEF") announced an increase in the regulated price for electricity, the first such increase in eight years.

Trust Unit Performance

The total return to unitholders in 2001 (distributions plus increase in unit price) was 42%. As shown in the graph on page 8, the Fund's performance compared very favourably to other trusts. While we are pleased with the recovery in the unit price, there are a number of factors driving the trading price of the Fund's units, many of which are outside of our direct control. However, the long-term contracts and management's ability to take advantage of opportunities as they arise give us a great deal of control over the level of distributions made by the Fund, and it continues to be our policy to provide unitholders with consistent and sustainable distributions with the objective of also achieving some growth.

**Opening of the Competitive Electricity
Market in Ontario**

We welcome the Ontario Government's definitive announcement that the Ontario competitive marketplace for electricity will open on May 1, 2002. The government has also made it clear that the power purchase agreements entered into by Ontario Hydro (including the Fund's) will continue to be honoured. A more detailed discussion on the opening of the competitive electricity market in Ontario, including the status of negotiations with OEF, can be found on pages 4 and 6 (Transition to a Competitive Market).

Acquisitions

In 2001, we diligently investigated a number of acquisition opportunities with the goal of increasing distributions to existing unitholders without changing the Fund's risk profile. However, our assessment was that the prices required

to acquire quality assets were too high in relation to the benefit that unitholders would receive. With Enron's demise in late 2001 and its impact on other industry participants, we believe that market conditions are becoming more favourable for interested buyers, such as the Fund.

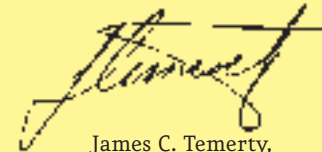
2002 Outlook

We expect that the upcoming year will present the Fund and its unitholders with opportunities, subject to conclusion of OEF negotiations. The opening of the electricity market in Ontario should provide upside income potential, and we will be looking into the economics of increasing the capacity of the Iroquois Falls facility.

For 2002, we are forecasting distributions of \$0.98 per unit, of which approximately 50% is anticipated to be tax-deferred. Monthly distributions are expected to be \$0.08 per unit, with the December 2002 distribution being \$0.10.

The strong effort and dedication of the employees at the Iroquois Falls plant keep on producing results. The Facility continues to operate at high levels of availability, which has contributed to the profitability of the Fund. Since plant start-up in September 1996, there have been no lost-time injuries, an exceptional record. I would like to thank the employees for another successful year.

On behalf of the administrator of the Fund and the Manager of the Iroquois Falls plant,



James C. Temerty,
President
Iroquois Falls Power Management Inc.
March 7, 2002



stewardship

Our plant has 15% excess capacity, and the opening of the Ontario electricity market should create a number of new opportunities. Importantly, cash flows continue to be buttressed by long-term contracts – the power purchase and steam sales agreements, natural gas supply and transportation contracts and an extended maintenance agreement for the most crucial plant components.

Transition to a Competitive Market

On December 18, 2001, the Premier of Ontario and Ontario's Minister of Energy, Science and Technology announced that the Ontario electricity market will open to competition on May 1, 2002.

Most importantly for the Fund, the Government of Ontario will continue to honour the power purchase agreement obligations after the market opens. As a result, the Fund will continue to receive the same steady revenue streams that serve to protect the Fund from volume and price risk for most of its revenues. Subject to OEFC negotiations, the Manager expects that the opening of the market may create upside opportunities for the Fund as discussed below.

Background

In October 1998, the Ontario government enacted the Energy Competition Act, 1998 (the "Act"), which provided for the restructuring of Ontario Hydro, the commercialization of the municipal electric utilities and, on a date to be determined by the Ontario government, the establishment of competitive wholesale and retail electricity markets and

open access for all electricity providers to transmission and distribution networks. The Act also mandated an expanded role for the Ontario Energy Board in the regulation and licensing of participants in the new electricity market.

Ontario Hydro was restructured on April 1, 1999, allowing Ontario Power Generation Inc. to take ownership over Ontario Hydro's electricity generation plants, including the nuclear stations. Hydro One Inc., through its wholly-owned subsidiary, Hydro One Networks Inc., assumed responsibility for bulk electricity transmission and is the entity that delivers electricity from the Iroquois Falls facility. The Independent Electricity Market Operator ("IMO") was created to ensure the matching of supply and demand in the new competitive market and is the entity to which the Fund would bid to sell electricity produced above the volumes specified in the long-term power purchase agreement. Overseeing competition in the Ontario market will be the shared responsibility of two agencies – the IMO and the Ontario Energy Board.

The legal successor to Ontario Hydro's obligations under the Facility's long-term power purchase agreement is Ontario

Electricity Financial Corporation ("OEFC"), an agency of the Province of Ontario that holds and administers the residual assets and liabilities of Ontario Hydro and particularly its debt, which was and continues to be guaranteed by the Government of Ontario.

Power Purchase Agreement

The most important aspect to the Fund of the new competitive market is that the long-term power purchase agreement will continue to underpin the bulk of the Fund's revenue and that an entity of the Government of Ontario continues to be obligated for that revenue. However, certain changes are required to the power purchase agreement to deal with the transition from a government monopoly to a competitive marketplace.

Negotiations with OEFC regarding needed changes to the power purchase agreement have been ongoing. Key transitional issues, which have industry-wide implications, that are still under discussion are: (i) the replacement of the Ontario Hydro price indices that form the basis for selling price changes under the power purchase agreement, and (ii) clarification of the ability of generators, such as the Iroquois Falls plant, to have access to the market for electricity sales beyond the volumes in the power purchase agreement. The Fund's manager has a leading industry role in these transition issues through the

involvement of two of its senior management in the Independent Power Producers' Society of Ontario, as president for 2002 and as co-chair of the industry committee working with OEFC on contract issues with industry-wide implications. The Manager and OEFC aim to conclude negotiations prior to market opening. If agreement has not been reached prior to May 1, a Contingency Trading Arrangement is in place with the IMO that will allow the Iroquois Falls plant to continue to operate under current power purchase agreement terms after market opening.

Competitive Market Readiness

Once the electricity markets are open to competition, the Iroquois Falls facility will be required to comply with market rules and procedures developed by the IMO and Ontario Energy Board. In preparation for these requirements, the Manager has undertaken a number of activities to ensure the Fund's readiness for successful participation in the new environment. The Manager has been working closely with the IMO to ensure that



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Our plant is only as good as the people who run it. Many are qualified stationary engineers, five certified at the highest level. Management actively encourages them to upgrade their skills and we reward them for this. Our safety record remains unblemished. All this means maximum uptime for the plant.

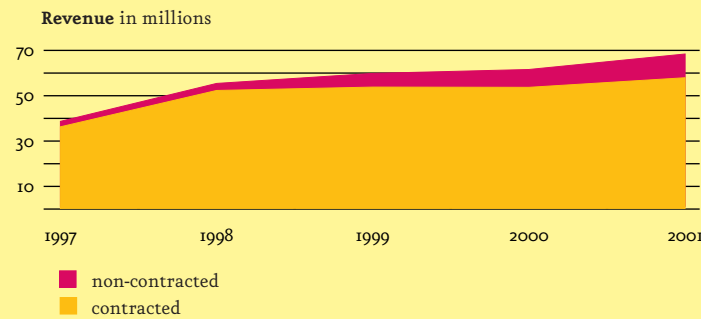
Transition to a Competitive Market all appropriate equipment and communications have been installed and are working properly, all appropriate application forms and data have been submitted in a timely fashion to the IMO and all staff have been trained on the requirements and the processes in the new market. These activities will ensure that the Iroquois Falls facility will meet the IMO's stringent requirements for highly reliable communications and metering. It is anticipated that the Iroquois Falls facility will have completed all testing and will be fully compliant with the IMO's open market system requirements well before the opening of the competitive market on May 1, 2002.

To facilitate the Fund's ability to participate in the competitive market and protect it from the associated costs, at last year's annual general meeting unitholders approved changes to the management agreement. It was agreed that the Manager would bear the on-going costs associated with complying with the technical and operational requirements of the new market rules (rather

than the Fund) and would absorb any one-time costs in excess of \$250,000, in return for a share of any future benefits achieved by the Fund.

Competitive Market Opportunities

Regulated wholesale prices for electricity in Ontario were frozen from 1992 to 2000. During this eight-year period, general prices as measured by the Consumer Price Index increased by approximately 14% in aggregate. The freeze



came to an end in 2001 with a 0.7¢/kWh increase in regulated rates that translated into an increase of 14% in the Ontario Hydro price indices to which the Fund's prices are tied. Approximately 8% of this increase in the indices was applicable to the Fund's 2001

results; the remainder will be received in 2002. The Manager anticipates that there will continue to be upwards pressure on electricity prices that will increase rates under the power purchase agreement.

The Fund has been making electricity sales to the Ontario Interim Market operated by Ontario Power Generation Inc. beyond OEFC's minimum purchase obligations under the power purchase agreement. This "market" is expected to be discontinued once the real

market opens on May 1, 2002. The Manager expects that open market prices will be higher than those received in the past from the Ontario Interim Market, and that there will be opportunities for higher

sales volumes, so the Fund will achieve better value for the 15% of plant capacity that is not committed under the power purchase agreement, subject to successful completion of negotiations with OEFC.

In the past, on occasions when Ontario Hydro had surplus capacity, it paid generators to shut down for specific periods; both parties benefited when cost savings were shared. The Manager expects OEFC to take a cooperative

and proactive approach to such opportunities for reducing its electricity purchase costs under contract once the market opens.

The Manager is also evaluating the economic feasibility of upgrading the gas turbines, partly to take advantage of opportunities created by the opening of the market.

As the graph on this page shows, the majority of the Fund's sales revenues are protected under long-term contracts and will continue to be protected once the electricity market opens to competition. The opening of the competitive market is expected to increase the non-contracted sales revenue of the Fund, subject to successful conclusion of negotiations with OEFC, thus creating upside potential for the Fund and its unitholders.

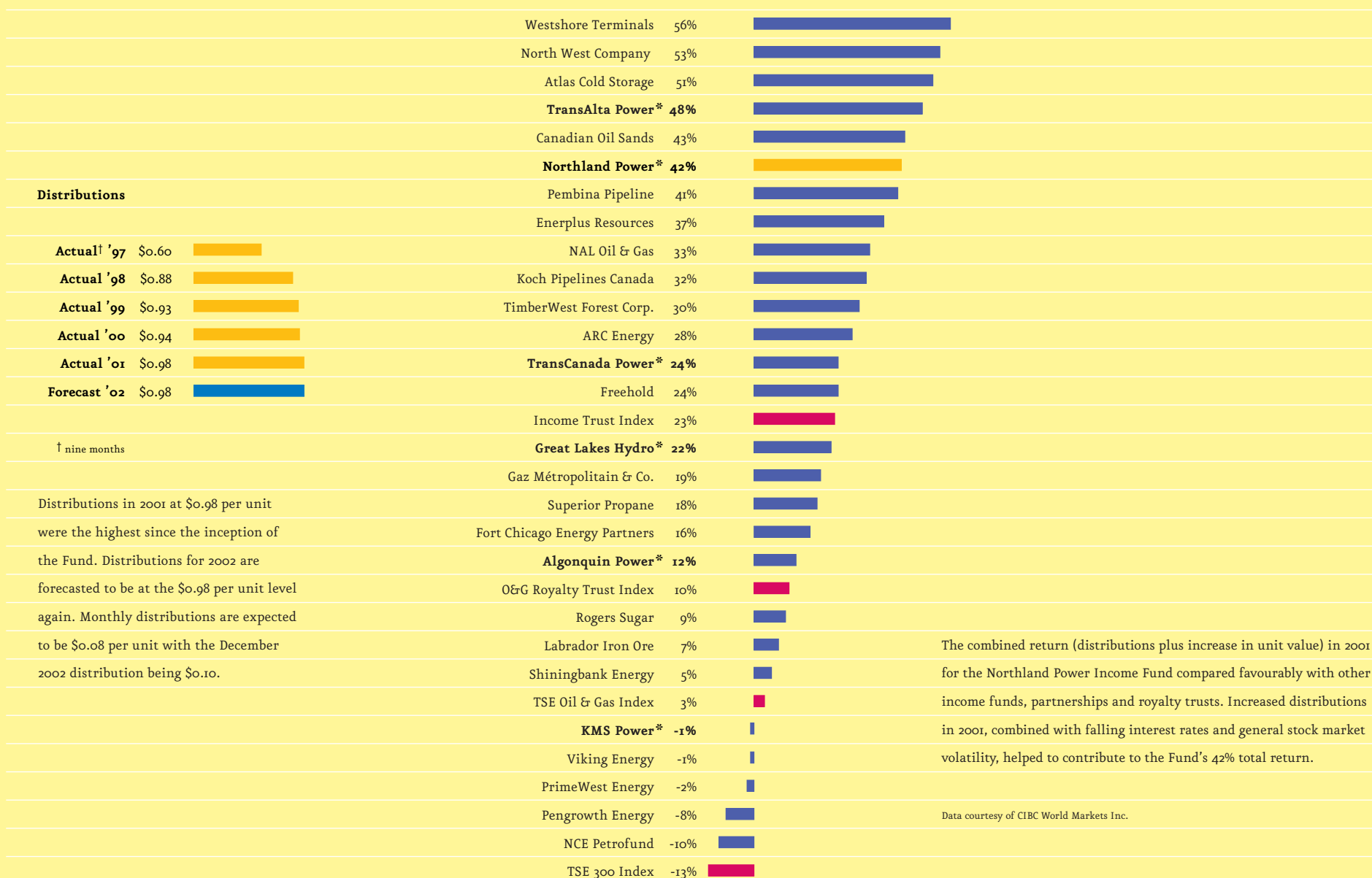


Everything is in place for us to take advantage of new opportunities in the year ahead.

We are able to produce more electricity, and with OEFC's co-operation, the competitive market should allow us to sell greater volumes for beneficial returns. This, in itself, will add value to our asset.

Prudent growth will increase that value even more.

Comparative Returns



Data courtesy of CIBC World Markets Inc.

* power funds

Distributions

Actual† '97 \$0.60
 Actual '98 \$0.88
 Actual '99 \$0.93
 Actual '00 \$0.94
 Actual '01 \$0.98
 Forecast '02 \$0.98

† nine months

Distributions in 2001 at \$0.98 per unit were the highest since the inception of the Fund. Distributions for 2002 are forecasted to be at the \$0.98 per unit level again. Monthly distributions are expected to be \$0.08 per unit with the December 2002 distribution being \$0.10.

The combined return (distributions plus increase in unit value) in 2001 for the Northland Power Income Fund compared favourably with other income funds, partnerships and royalty trusts. Increased distributions in 2001, combined with falling interest rates and general stock market volatility, helped to contribute to the Fund's 42% total return.

**Governance:
The Roles of the
Trustee, the IFPC
Board and
the Manager**

As Trustee, Montreal Trust Company of Canada has responsibility for the administration of the Fund. The Trustee has delegated administrative responsibility for the Fund to Iroquois Falls Power Management Inc. (the “Manager”) under an administration agreement.

The Board of Directors of IFPC has responsibility for the management of the Facility, the administration of the contracts and the operation of the business of selling electricity and

steam. In addition, the Board reviews the operations of the Fund and provides advice to the Manager. The Board consists of five directors, four of whom are independent of the Manager. The Board has delegated the day-to-day management responsibilities to the Manager under a management agreement expiring in 2021.

**Directors* and
Officers of
Iroquois Falls
Power Corp.**



James C. Temerty*



Anthony F. Anderson



Linda L. Bertoldi



Pierre R. Gloutney*



A. Warren Moysey*



F. David Rounthwaite*



The Right Honourable
John N. Turner, Q.C.*

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**Distribution and
Funding Policy**

It is the Fund’s policy to distribute 100% of estimated cash flow to unitholders after providing for capital reserves and any increases in working capital, which are not expected to be material. Any permitted acquisitions and plant expansions would be funded by a combination of borrowings and the issuance of additional trust units.

**Management’s
Discussion
and Analysis**

The following is a discussion of the consolidated financial condition and results of operations of Northland Power Income Fund (the “Fund”). It should be read in conjunction with the audited consolidated financial statements on pages 16 to 23.

The annual report, including this Management’s Discussion and Analysis, contains forward-looking statements with respect to the Fund and its wholly-owned subsidiary, Iroquois Falls Power Corp. (“IFPC”), based on assumptions that management considered reasonable at the time they were prepared. These forward-looking statements, by their nature, necessarily involve risks and uncertainties that could cause actual results to differ materially from those contemplated by the forward-looking statements. Some of the factors that could cause results or events to differ from current expectations include, but are not limited to, the factors described on pages 14 and 15.

The Fund’s 2001 distributions to unitholders of \$30.2 million, or \$0.98 per unit, exceeded distributions for the year 2000 by \$0.04 per unit primarily because of higher funds generated from operations.

Sales

In thousands of dollars except as indicated otherwise

	2001	2000
Electricity		
Production and sales volume (MWh)	739,701	739,687
Average price (\$/kWh)	0.0737	0.0684
Sales	54,545	50,570
Steam		
Production and sales volume (000 lb.)	1,012,015	997,164
Average price (\$/000 lb.)	5.29	4.52
Sales	5,358	4,504
Natural Gas	8,508	6,502
Total Sales	\$68,411	\$61,576

Electricity sales revenue in 2001 exceeded the 2000 level by \$4.0 million because of higher prices received under the long-term power purchase agreement.

Electricity price changes under the power purchase agreement are tied to changes in the Ontario Hydro selling price indices (the Direct Customer Rate and the Average Customer Rate). The Fund’s revenues from electricity sales under the power purchase agreement are directly tied to changes in these indices, although approximately 23% of such electricity sales revenue is subject to 3.3% minimum annual escalation.

During the year, Ontario Power Generation Inc. announced a 0.7¢/kWh increase in the regulated wholesale electricity price effective June 1, 2001. This resulted in Ontario Electricity Financial Corporation (“OEF”) increasing the Direct Customer Rate and Average Customer Rate by 14.0%; approximately 8.2% of this increase was applicable to 2001. Through the price escalation mechanism in the power purchase agreement with OEF, this resulted in a 7.4% average electricity price increase to the Fund for 2001. In addition, OEF shared in the impact of the natural gas cost increase under the price re-opener provisions of one of the natural gas contracts, which also increased the Fund’s revenue. Ontario Power Generation Inc.’s price increase in 2001 will also affect the Fund’s electricity selling price in 2002, when the remainder of the Direct Customer Rate and Average Customer Rate increases will be received.

Steam sales revenue was 19.0% higher in 2001. While Abitibi-Consolidated Company of Canada (“Abitibi”) purchased 1.5% more steam, the major change was an increase in the steam selling price of 12.5%, roughly in line with the higher price of natural gas, which largely determines the steam selling price under the steam sales agreement. Also, 2001 steam revenue was boosted by \$0.2 million of revenue deferred from 2000 but recognized in 2001 when the winter take-or-pay reconciliation was completed.

Management's
Discussion
and Analysis

Sales revenue of \$8.5 million was received for natural gas that was resold to mitigate the cost of unused capacity under the transportation contract with TransCanada PipeLines Limited. Natural gas sales in 2001 were \$2.0 million above the 2000 level due to favourable market prices. Sales of natural gas in 2002 are not expected to be as high as the previous two years due to significantly lower market prices projected for natural gas. The Fund will, however, continue to mitigate its fixed transportation costs whenever future opportunities arise.

Cost of Sales

In thousands of dollars except as indicated otherwise	2001	2000
Natural Gas		
Volume of gas consumed (000 GJ)	6,963	6,935
Average price of gas consumed (\$/GJ)	3.52	3.19
Cost of gas consumed	24,490	22,119
Cost of Natural Gas Purchased for Resale	4,079	3,465
Total Cost of Sales	\$28,569	\$25,584

The cost of natural gas consumed at \$24.5 million was \$2.4 million higher than the prior year. The volume of gas consumed was in line with last year, while the average cost increased by 10.3% due to price increases under the terms of the long-term gas contracts and a 10% increase in the TransCanada PipeLines tariff. Included in the higher prices was the impact of a 15% increase related to the "re-opening" on January 1, 2001, of the price under one gas contract that represents approximately 60% of the Fund's gas consumption. Half of this price increase was absorbed by OEFC through the provisions of the power purchase agreement as noted above, so the impact on the cash flow of the Fund was equivalent to a 7.5% price increase. Commensurate with the increase in contractual prices and a higher level of TransCanada PipeLines Limited cost mitigation, the cost of natural gas purchased for resale totalled \$4.1 million, \$0.6 million higher than 2000.

Expenses Including Interest

In thousands of dollars except as indicated otherwise	2001	2000
Plant operating costs	\$6,641	\$5,967
Amortization	9,243	9,240
Management & administration costs, including capital tax	3,428	2,027
Interest and bank fees	126	135
Interest income	(247)	(259)
Total Expenses Including Interest	\$19,191	\$17,110

Plant operating expenses were \$0.7 million or 11.3% higher than 2000. Fees under the General Electric Canada Inc. maintenance and lease club agreement, which are payable in U.S. dollars, increased by approximately 6.5% largely because of the weaker Canadian dollar. Plant maintenance costs in 2001 included \$0.3 million for expenditures related to the steam turbine generator stator, with an additional \$1.2 million anticipated to be incurred in 2002 as a one-time expenditure to replace the stator during the next major maintenance shutdown.

Management and administration costs were \$1.4 million ahead of last year because of an increase in incentive fees to the Manager of \$1.3 million related to gas management.

Overall, increased gross profit from electricity, steam and gas sales partially offset by higher expenses resulted in net income in 2001 at \$20.6 million, exceeding the 2000 level by \$1.7 million.

Management's
Discussion
and Analysis

Distributions to Unitholders		
In thousands of dollars except as indicated otherwise	2001	2000
Funds from Operations Before Working Capital Changes		
Net change in non-cash working capital	\$30,978	\$29,194
	1,017	(6,059)
Cash Provided by Operating Activities		
Add: capital expenditures, net of restricted cash	\$31,995	\$23,135
Less: funds set aside for future maintenance costs	42	63
	(86)	(82)
Cash Available for Distribution		
	\$31,951	\$23,116
Distributions Declared to Unitholders		
	\$30,207	\$28,974
Number of trust units (thousands of units)	30,823	30,823
Per Unit (\$/unit)		
Funds from operations before working capital changes	\$1.01	\$0.95
Cash available for distribution	\$1.04	\$0.75
Distributions declared to unitholders	\$0.98	\$0.94

Funds from operations before changes in working capital at \$31.0 million exceeded the 2000 level by \$1.8 million. Cash available for distribution at \$32.0 million was \$8.8 million higher than the year-earlier level, which was affected by a significant increase in working capital, discussed in last year's annual report, related primarily to timing of the receipt of payment from OEFC for electricity sales in November 2000 – payment was received three days after year-end due to the incidence of weekends and holidays in December 2000. Payment of \$5.6 million for November sales was similarly delayed in 2001 (to January 3, 2002).

Distributions declared to unitholders for 2001 totalled \$30.2 million or \$0.98 per unit, compared to \$29.0 million and \$0.94 per unit in 2000.

Tax Treatment of Distributions

Distributions to unitholders in 2001 were 76.9% tax-deferred. The tax deferral arises as the Fund's capital cost allowance and expenses significantly reduce the Fund's income that would otherwise be taxable. The tax-deferred portion of distributions represents a return of capital for Canadian income tax purposes and reduces the adjusted cost base of the units.

Generally, a trust unit is considered to be capital property. The actual or deemed disposition of a unit will give rise to a capital gain (or loss) equal to the amount by which the proceeds of disposition of a unit are greater (or less) than the adjusted cost base of the unit and any associated selling expenses.

Distributions in 2002 are expected to be approximately 50% tax-deferred and 50% taxable to unitholders.

Seasonality of Cash Available for Distribution

The Fund's cash available for distribution is seasonal as OEFC has contracted for more electricity and pays a higher price in winter than in summer. In addition, steam sales to Abitibi are higher in winter. Since August 2000, distributions to unitholders have been made on a monthly basis (rather than quarterly) and have been levelized in order to provide investors with regular, predictable monthly investment income.

Liquidity and Capital Resources

The Fund had no long-term debt at December 31, 2001. The Fund's subsidiary, IFPC, has a line of credit of \$12.5 million consisting of a \$7.5 million revolving letter of credit facility used in meeting obligations under the TransCanada PipeLines Limited contract and a \$5 million revolving operating line of credit to be used for general corporate purposes. As of December 31, 2001, a letter of credit for \$5.9 million was outstanding, and there were no borrowings under the operating line of credit.

The Fund ended the year with a cash balance of \$0.5 million. Receipt of \$5.6 million for November electricity sales to OEFC was delayed to January 3, 2002, which accounts for the high level of accounts receivable at December 31, 2001, albeit in line with the 2000 year-end level, which had a similar payment delay of a few days over year-end. Cash at year-end plus the aforementioned \$5.6 million is available to fund distributions payable to unitholders at year-end of \$4.2 million as well as the planned replacement of the steam turbine generator stator for an estimated \$1.2 million in 2002.

Distribution and Funding Policy

It is the Fund's policy to distribute 100% of estimated cash flow to unitholders after providing for capital reserves and any increases in working capital, which are not expected to be material. Any permitted acquisitions and plant expansions would be undertaken only if approved by the IFPC Board of Directors and funded by a combination of borrowings and the issuance of additional units.

Commitments

The Facility generates electricity and sells it to OEFC under a power purchase agreement expiring in 2021. The power purchase agreement obligates OEFC to purchase quantities of electricity ranging from a monthly average of 77 MW in the summer months to 96 MW in the winter (the yearly average is approximately 85 MW).

Steam is supplied by the Facility to the neighbouring Abitibi pulp and paper mill under a steam sales agreement that expires in 2016.

The Facility is fuelled by natural gas provided by PanCanadian Petroleum Limited, Shell Canada Ltd. and Calpine Canada Resources Ltd. (formerly Encal Energy Ltd.) pursuant to gas supply contracts that end at various times between 2015 and 2017. The gas is transported through pipelines owned by TransCanada PipeLines Limited and Union Gas Limited from Western Canada to the plant site under firm service agreements that run to 2016.

The maintenance of the two LM 6000 gas turbines is contracted to General Electric Canada Inc. under a maintenance agreement that was extended in 2000 and now expires in 2008 and is further renewable at IFPC's option under similar terms.

The unionized employees at the Iroquois Falls facility work under a collective agreement that expires June 30, 2002. Negotiations for the second collective agreement with the Iroquois Falls plant employees will be under way after the 2001 year-end.

The Facility is operated by Iroquois Falls Power Management Inc. (the "Manager"), a wholly-owned subsidiary of Northland Power Inc., which is indirectly owned by a director of IFPC, under a management agreement expiring in 2021. The Manager administers the Fund under the administration agreement.

A summary of these agreements can be found on the Fund's web site at www.NPIFund.com.

Risks and Uncertainties

The amount distributed by the Fund to unitholders is dependent upon the parties to the Fund's long-term contracts continuing to fulfill their contractual obligations. In particular, as electricity sales represent up to 90% of the Fund's revenues, failure of OEFC to meet its contractual obligations would have an adverse affect on distributions.

On April 1, 1999, Ontario Hydro was reorganized into five successor companies. OEFC, one of the successor companies, holds all rights, obligations and liabilities related to the power purchase agreement. Both the Ontario government and OEFC have stated that they are committed to continuing to honour the Facility's long-term power purchase agreement notwithstanding the restructuring of Ontario Hydro and the opening of the competitive electricity market on May 1, 2002.

Increases in the selling price of electricity under the power purchase agreement are indexed to Ontario Hydro selling price indices (the Direct Customer Rate and Average Customer Rate). The Fund's revenues from electricity sales under the power purchase agreement are directly tied to changes in the Direct Customer Rate and the Average Customer Rate, although approximately 23% of such electricity revenue is subject to 3.3% minimum escalation. Discussions with OEFC are under way to establish mutually satisfactory replacements for the Direct Customer Rate and the Average Customer Rate indices; this is an issue that affects a significant number of other holders of long-term power purchase agreements with OEFC in addition to the Fund. The impact that such replacements may have on future electricity price changes under the power purchase agreement is not yet determinable.

The Fund has generated revenue from electricity sales to the Ontario Interim Market operated by Ontario Power Generation Inc. and, prior to Ontario Power Generation's formation, Ontario Hydro. Although the Manager considers otherwise, it is the position of OEFC that the Fund is required to sell any electricity it generates in excess of the quantities under the power purchase agreement exclusively to OEFC. The Ontario Interim Market is expected to be discontinued once the competitive market opens. The Fund may not be permitted to sell electricity outside the terms of the power purchase agreement to the competitive market unless this matter is resolved during the negotiations with OEFC.

In the event that negotiations with OEFC are not completed by the opening of the market, a Contingency Trading Arrangement has been agreed to with the Independent Market Operator that will allow the Iroquois Falls plant to continue to operate under current power purchase agreement terms after market opening.

As a result of the opening of the competitive market, some additional costs, such as generator licensing fees, will also arise. Participation in the competitive electricity market may expose the Fund to additional risks. The Manager is establishing procedures to minimize such exposure.

Abitibi's demand for steam is determined by operations at its Iroquois Falls pulp and paper mill, including the level of its own steam production. The Facility is obliged to respond to fluctuations in Abitibi's steam needs. Demand for steam has an impact on natural gas consumption, and unexpectedly large short-term fluctuations in steam demand increase natural gas consumption without a proportionate increase in steam revenue. The Abitibi mill in Iroquois Falls continues to be very competitive in its industry segment, ranked by one investment bank analyst in the best third within North America in terms of cost, and is therefore well positioned to continue to be a long-term customer. The Fund is protected from the economic impact of any adverse changes at Abitibi's mill until 2003 by the take-or-pay provisions in the steam sales agreement that obligate Abitibi to pay for a minimum quantity of steam. Beginning on January 1, 2002, the Fund is further protected through provisions of the power purchase agreement that increase OEFC's electricity purchase obligations to make up for any shortfalls in steam revenue.

Contracted natural gas prices generally escalate with Ontario Hydro's Direct Customer Rate subject to a 4% minimum annual increase. The natural gas contracts provide for price adjustments (subject to predefined ceilings) approximately every five years for which 50% of any resulting incremental costs are borne by OEFC. Alternatively, the periodic natural gas price adjusters could decrease contracted natural gas prices relative to electricity prices; OEFC shares in approximately 40% of any such savings. The impact of replacing the Direct Customer Rate as escalator in the natural gas contracts is not yet determinable. Failure by the Facility's natural gas suppliers to provide natural gas under the long-term contracts could result in higher natural gas prices.

Any failure by TransCanada PipeLines Limited or Union Gas Limited to deliver natural gas to the Facility will have an adverse impact on cash distributions.

The Fund is subject to operational risks that could have an adverse affect on cash distributions. These risks are partially mitigated by the proven nature of the technology and design of the Facility, the availability of critical spares on site, the gas turbine maintenance agreement with General Electric Canada Inc. and participation in the General Electric Canada Inc. gas turbine lease pool, which guarantees the availability of replacement gas turbines on short notice. The Fund has business interruption insurance to help mitigate the impact on distributions of other adverse occurrences that are insured.

There is a risk of production disruptions in the event that a settlement cannot be reached on the terms of a new collective agreement to replace the current contract that expires June 30, 2002. Management has no reason to expect such disruptions at the current time.

The Facility operations are subject to numerous environmental laws and regulations. The Fund has an environmental monitoring and reporting system in place. Changes in environmental laws and regulations could possibly result in additional expenses, capital expenditures and restrictions in the Facility's activities, the extent of which cannot be predicted. One such change is modifications to environmental regulations in Ontario announced in 2001 that will further limit

nitrogen oxides (NO_x) emissions when they become effective in 2004. A review of the impact on the Facility and what actions need to be taken, if any, has begun.

The Fund is reliant upon the Manager for the administration and management of all matters relating to the Facility.

Outlook

While the Fund will face higher costs in 2002 due to scheduled natural gas contract price increases, anticipated higher gas transportation tariffs and higher plant maintenance costs, electricity selling price increases effective January 1, 2002 under the long-term power purchase agreement with OEFC are expected to largely, if not totally, offset these higher costs. As a result, distributions to unitholders for 2002 are expected to be consistent with 2001 at \$0.98 per unit. Monthly distributions are forecasted to be \$0.08 per unit with the December 2002 distribution being \$0.10.

The announced opening of the competitive electricity market in Ontario on May 1, 2002, is expected to offer the Fund and its unitholders significant opportunities and benefits, including increased volumes and prices for electricity sales outside the terms of the power purchase agreement, subject to successful completion of negotiations with OEFC. In addition, more active management of electricity supply under the power purchase agreement in cooperation with OEFC has the potential to benefit the Fund through sharing in cost savings.

The Fund will continue to seek acquisition and investment opportunities that meet its criteria for increasing distributions while also protecting the Fund's current risk profile.

Auditors' Report

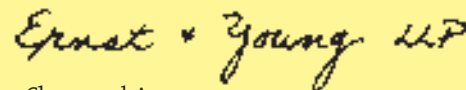
To the Unitholders of Northland Power Income Fund

We have audited the consolidated balance sheets of Northland Power Income Fund as at December 31, 2001 and 2000, and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Manager of the Fund. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance 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.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2001 and 2000, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Toronto, Canada
March 1, 2002


Chartered Accountants

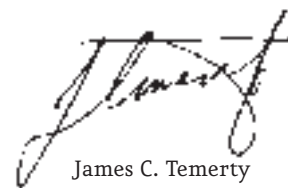
**Consolidated
Balance Sheets**

As at December 31,
in thousands
of dollars

Assets	2001	2000
Current		
Cash and cash equivalents	496	—
Restricted cash [note 1]	80	211
Accounts receivable [note 3]	12,111	12,569
Inventories [note 4]	1,365	1,673
Prepaid expenses	814	576
Total Current Assets	14,866	15,029
Deferred maintenance fee, net	813	1,905
Capital assets, net [note 5]	230,271	239,425
Future income tax asset [note 10]	1,429	1,432
	247,379	257,791
Liabilities and Unitholders' Equity		
Current		
Bank indebtedness [note 6]	—	2,105
Accounts payable and accrued liabilities	4,835	4,346
Distribution payable to unitholders	4,161	3,390
Total Liabilities	8,996	9,841
Commitments and contingencies [notes 6 and 11]		
Unitholders' Equity [note 7]	238,383	247,950
	247,379	257,791

See accompanying notes.

Approved on behalf of Northland Power Income Fund
by Iroquois Falls Power Management Inc.



James C. Temerty
President

**Consolidated
Statements
of Income
and Deficit**

Years ended
December 31

In thousands of
dollars, except
per unit
information

	2001	2000
Sales		
Electricity	54,545	50,570
Steam	5,358	4,504
Natural gas	8,508	6,502
	68,411	61,576
Cost of sales	28,569	25,584
Gross Profit	39,842	35,992
Expenses		
Plant operating costs	6,641	5,967
Amortization	9,243	9,240
Management and administration costs [note 9]	3,428	2,027
Interest expense and bank fees	126	135
Interest income	(247)	(259)
	19,191	17,110
Income before income taxes	20,651	18,882
Provision for (recovery of) income taxes [note 10]		
Current	8	20
Future	3	(103)
	11	(83)
Net Income for the Year	20,640	18,965
Deficit, beginning of year	(42,202)	(32,193)
Distributions to unitholders [note 8]	(30,207)	(28,974)
Deficit, End of Year [note 7]	(51,769)	(42,202)
Net Income per Trust Unit [note 2]	\$0.67	\$0.62

See accompanying notes.

Consolidated Statements of Cash Flows	Operating Activities	2001	2000
Years ended December 31 In thousands of dollars	Net income for the year	20,640	18,965
	Add items not involving cash:		
	Amortization	9,243	9,240
	Amortization of maintenance fee	1,092	1,092
	Future income taxes	3	(103)
	Funds from operations before changes in working capital	30,978	29,194
	Net change in non-cash working capital balances related to operations	1,017	(6,059)
	Cash Provided by Operating Activities	31,995	23,135
	Investing Activities		
	Purchase of capital assets	(89)	(152)
	Cash Used in Investing Activities	(89)	(152)
	Financing Activities		
	Restricted cash drawdown	131	215
	Increase (decrease) in bank indebtedness	(2,105)	2,105
	Distributions to unitholders	(29,436)	(33,290)
	Cash Used in Financing Activities	(31,410)	(30,970)
	Net Increase (Decrease) in Cash and Cash Equivalents		
	During the Year	496	(7,987)
	Cash and cash equivalents, beginning of year	-	7,987
	Cash and Cash Equivalents, End of Year	496	-
	Supplemental Cash Flow Information		
	Interest paid	10	23
	Income taxes paid	8	20

See accompanying notes.

**Notes to
Consolidated
Financial
Statements**

December 31, 2001

1. Description of Business

Northland Power Income Fund (the “Fund”) was established under the laws of the Province of Ontario pursuant to a Declaration of Trust. The Fund derives its distributable cash flow from Iroquois Falls Power Corp. (“IFPC”), a special-purpose corporation, wholly-owned by the Fund. The Iroquois Falls cogeneration power facility (the “Facility”) produces electricity for sale to Ontario Electricity Financial Corporation (“OEF”) under the provisions of a contract expiring in 2021 and steam for sale to Abitibi-Consolidated Company of Canada (“Abitibi”) under the provisions of a contract expiring in 2016. Natural gas for the Facility is purchased under long-term contracts expiring in the years 2015 to 2017.

As part of the acquisition, restricted cash of \$1,983,000 was acquired in order to complete the construction of the plant. At December 31, 2001, the restricted cash balance is \$80,000 (2000 – \$211,000). During the year, \$131,000 of restricted cash was used to purchase capital assets (2000 – \$215,000).

2. Summary of Significant Accounting Policies

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and within the framework of the significant accounting policies summarized as follows:

Principles of consolidation

These consolidated financial statements include the accounts of the Fund and the accounts of IFPC. All inter-entity transactions have been eliminated.

Cash and cash equivalents

Cash equivalents comprise only highly liquid investments with original maturities of less than 90 days and are recorded at cost, which approximates market value.

Use of estimates

The preparation of consolidated financial statements in conformity with GAAP requires that Iroquois Falls Power Management Inc. (the “Manager”), the administrator of the Fund and the manager of the Facility, make estimates and assumptions about future events that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements, and revenue and expenses during the reporting period. Actual results could differ from those estimates.

Inventories

Inventories comprise natural gas, spare parts and other inventory. Natural gas is carried at the lower of cost, as determined on a weighted average basis, and net realizable value. Spare parts and other inventory are carried at the lower of cost and net replacement cost.

Capital assets

Capital assets are recorded at cost less accumulated amortization. Amortization is provided on a straight-line basis at rates designed to amortize the cost of the assets over their estimated useful lives as follows:

Buildings and foundations	30 years
Plant and equipment	30 years
Contracts [note 3]	over the term of the agreements
Vehicles	5 years
Office equipment, furniture and fixtures	5 years
Computers and computer software	2 years

Deferred maintenance fee

The deferred maintenance fee is amortized over the original term of the agreement, between IFPC and General Electric Canada Inc. for the maintenance of the gas turbines, which expires in 2002. This agreement has been extended without prepayment to 2008 and is renewable upon expiry.

Revenue recognition

Revenue for electricity and natural gas is recognized upon delivery. Revenue for steam is recognized at the take-or-pay level upon delivery; additional revenue above this level is recognized upon completion of the take-or-pay reconciliation at predetermined dates during the year.

Net income per trust unit

Net income per trust unit is based on the consolidated net income for the year divided by the weighted average number of trust units outstanding during the year, which was 30,823,443 (2000 – 30,823,443).

Income taxes

The Fund follows the liability method of tax allocation, whereby future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Under the terms of the Income Tax Act (Canada), the Fund is not subject to income taxes to the extent that its taxable income in a year is paid or payable to a unitholder. Accordingly, no provision for current income taxes for the Fund is made. In addition, as the Fund is contractually committed to distribute to its unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable in the Fund, the Fund intends to continue to meet the requirements under the Income Tax Act applicable to such trusts, and there is no indication that the Fund will fail to meet those requirements, the Fund is not subject to the recommendations of the CICA section 3465.

The Fund's wholly-owned subsidiary, IFPC, is subject to corporate income taxes as computed under the Income Tax Act and CICA section 3465.

3. Economic Dependence and Concentration of Credit Risk

The Fund is entirely dependent on the facility lease income, interest income and dividends received from IFPC. In 2001, approximately 80% (2000 – 82%) of IFPC's revenue was derived from the sale of electricity to OEFC. Approximately 8% (2000 – 7%) of IFPC's revenue was derived from the sale of steam to Abitibi.

Approximately 93% (2000 – 84%) of the year-end accounts receivable balance was due from OEFC relating to electricity sales. Approximately 5% (2000 – 5%) of the year-end accounts receivable balance was due from Abitibi relating to steam sales.

4. Inventories – In thousands of dollars

Inventories consist of the following:	2001	2000
Natural gas	457	732
Spare parts and other inventory	908	941
	1,365	1,673

5. Capital Assets – In thousands of dollars

Capital assets consist of the following:	2001		2000	
	Cost	Accumulated amortization	Cost	Accumulated amortization
Land	126	–	126	–
Buildings and foundations	23,159	3,664	23,159	2,892
Plant and equipment	237,020	37,484	236,950	29,585
Contracts	13,668	2,597	13,668	2,050
Vehicles	26	14	26	9
Office equipment, furniture and fixtures	68	44	57	32
Computers and computer software	99	92	91	84
	274,166	43,895	274,077	34,652
Net book value		230,271		239,425

6. Credit Agreement

The Fund has a credit agreement with the Canadian Imperial Bank of Commerce that is subject to renewal on the anniversary date of April 16, 2002, which establishes a \$7,500,000 revolving-term letter of credit facility to be used in meeting obligations under gas transportation and supply contracts and a \$5,000,000 revolving-term operating line of credit for general corporate purposes. Interest per annum under the operating line of credit agreement is charged at the bank's prime rate plus 2.0% (6% at December 31, 2001). There is also a fee of 1.3% per annum charged on the outstanding amount of the letter of credit. Standby fees of 0.5% are charged on each of the undrawn letter of credit and operating line facilities.

As at December 31, 2001, a letter of credit for \$5,920,000 (2000 – \$5,920,000) was outstanding under the letter of credit facility. As at December 31, 2001, nil (2000 – \$2,105,000) has been drawn on the operating line.

Amounts drawn under the credit agreement are principally collateralized by a debenture security and by general security agreements that constitute a first priority lien on all of the real property and all of the present and future property assets of IFPC and the Fund, as well as a pledge by the Fund of its current and future interests in the capital stock of IFPC, notes payable and all other securities issued by IFPC to the Fund.

7. Unitholders' Equity

The Fund may issue an unlimited number of trust units subject to rules governing the trust indenture. Each trust unit represents an equal fractional beneficial interest in the Fund. All trust units are transferable and share equally in all distributions from the Fund whether of net income, return of capital, return of principal, interest, dividends or net realized capital gains or other amounts, and in the net assets of the Fund in the event of termination or winding-up of the Fund.

	2001	2000
Issued and outstanding		
30,823,443 trust units	290,152	290,152
Deficit	(51,769)	(42,202)
	238,383	247,950

The trust units are redeemable at any time on demand by the holders at their fair value, determined as the lesser of: (a) 95% of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10-trading-day period commencing immediately after the date on which the trust units are surrendered for redemption; and (b) the "closing market price" on the principal market on which the trust units are quoted for trading on the date that the trust units are surrendered for redemption.

The aggregate redemption price payable by the Fund in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month, provided that the entitlement of unitholders to receive cash upon redemption of their trust units is subject to the limitations that (a) the total amount payable by the Fund in respect of such trust units and all other trust units tendered for redemption in the same calendar month shall not exceed \$200,000, (b) at the time such trust units are tendered for redemption the outstanding trust units of the Fund shall be listed for trading on a stock exchange or traded or quoted on any other market that IFPC's Directors consider, in their sole discretion, provides representative fair market value prices for the trust units, or (c) the normal trading of trust units is not suspended or halted on any stock exchange on which the trust units are listed on the date that the trust units are tendered for redemption or for more than five trading days during the 10-trading-day period commencing immediately after the date on which the trust units are tendered for redemption.

8. Distributions to Unitholders

Cash provided by operating activities for the year ended December 31, 2001, was \$1.04 per trust unit (2000 – \$0.75 per trust unit), being an aggregate amount of \$31,995,000 (2000 – \$23,135,000).

Distributions totalling \$0.98 per trust unit (2000 – \$0.94), being aggregate distributions of \$30,207,000 (2000 – \$28,974,000), were determined by the Manager of the Fund for the year ended December 31, 2001. For income tax purposes, \$23,241,000 or 76.9% (2000 – \$28,510,000 or 98.4%) of the distributions is a return of capital.

9. Management Fee

The Manager, a company which is indirectly controlled by a director of IFPC, is entitled to receive a fee from the Fund and IFPC for services provided related to the operation, management and administration of the Facility, pursuant to a 25-year management agreement expiring in 2021. The fee is payable on a monthly basis at a rate of $\frac{1}{12}$ of \$460,000, adjusted annually with changes to the Consumer Price Index. During the year ended December 31, 2001, the Manager was paid \$493,000 (2000 – \$478,000).

The Manager is also entitled to other operation-related incentive fees. During the year ended December 31, 2001, the Manager earned \$1,719,000 (2000 – \$397,000) as an operation-related incentive fee, which is calculated as a percentage of the profit earned by the Fund on the resale of natural gas, excluding the allocation of fixed transportation demand charges. In addition, the Manager may receive a management incentive fee equal to 25% of the amount by which annual distributions to the unitholder exceed \$0.934 per unit, less the amount of certain operational incentive fees. During the year ended December 31, 2001, the Manager was paid nil (2000 – nil).

10. Income and Other Taxes

In thousands of dollars	2001	2000
The components of income tax expense (recovery) are as follows:		
Current		
Federal	8	20
Provincial	–	–
Future		
Federal	2	(66)
Provincial	1	(37)
Provision for (Recovery of) Income Taxes	11	(83)
The components of future income tax liabilities and assets are as follows:		
Future Tax Liabilities		
Capital assets book value in excess of UCC	–	161
Total future tax liabilities	–	161
Future Tax Assets		
UCC in excess of capital assets book value	623	–
Loss carryforwards	806	1,593
Total future tax assets	1,429	1,593
Net Future Tax Assets	1,429	1,432
Income before income taxes	20,651	18,882
Combined federal and provincial income tax at statutory rate of 42.12% (2000 – 43.95%)	8,698	8,299
Manufacturing and processing deduction	(1,000)	(604)
Income of Fund distributed to unitholders	(7,917)	(7,906)
Future income tax expense resulting from rate change	222	108
Large Corporations Tax and other items	8	20
Provision for (Recovery of) Income Taxes	11	(83)

At December 31, 2001, financing expenses and underwriters' fees of \$465,682 (2000 – \$4,082,000) are deductible by the Fund for income tax purposes on a straight-line basis over the next year.

At December 31, 2001, IFPC has non-capital losses available for carryforward of approximately \$2,676,000, which are available to reduce future year taxable income. These losses expire in 2005.

11. Commitments

IFPC has entered into agreements for the supply of natural gas for various terms to 2017. These agreements were entered into in the normal course of business to purchase natural gas for IFPC's electricity and steam generation operation on terms that would protect the profitability of sales under the long-term power purchase agreement with OEFC. There are no penalties for failure to purchase natural gas under these contracts; however, failure to purchase the minimum quantities required under these contracts could reduce the maximum quantities available for purchase under the respective agreements.

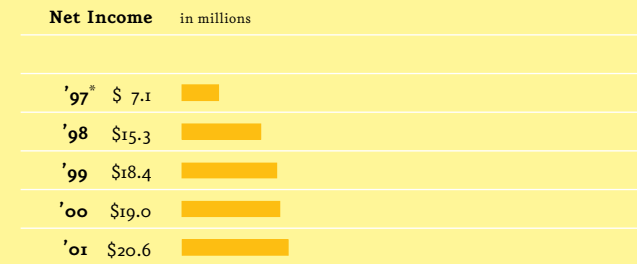
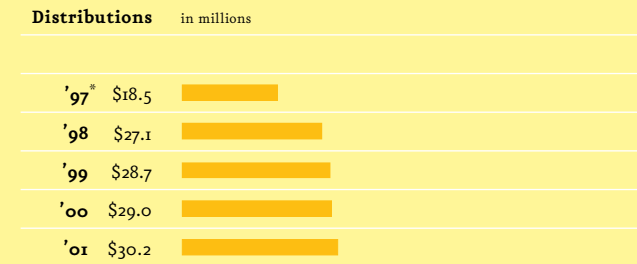
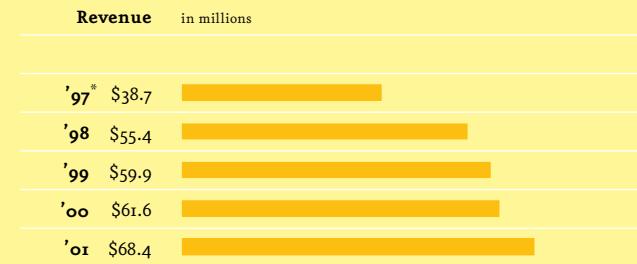
IFPC has entered into agreements for gas transportation that incorporate standard industry terms including the approval of tariffs by applicable regulated authorities. The natural gas transportation agreements include substantial demand charges, which are incurred whether or not natural gas is shipped.

**Historical
Review**

Years ending
December 31
In thousands of
dollars, except
as specified

	2001	2000	1999	1998	1997 †
Financial					
Electricity production (MWh)	739,701	739,687	778,307	732,034	517,058
Steam production (ooo lb.)	1,012,015	997,164	868,431	779,609	769,833
Sales					
Electricity	\$54,545	\$50,570	\$51,704	\$49,588	\$34,063
Steam	5,358	4,504	4,381	3,713	3,067
Gas	8,508	6,502	3,765	2,128	1,561
	68,411	61,576	59,850	55,429	38,691
Cost of Sales	28,569	25,584	25,166	22,048	15,090
Gross Profit	39,842	35,992	34,684	33,381	23,601
Expenses					
Plant operating costs	6,641	5,967	5,762	5,890	4,076
Amortization	9,243	9,240	9,242	9,250	6,922
Management and administration costs	3,428	2,027	1,473	1,337	924
Interest expense and bank fees	126	135	112	1,996	4,629
Interest income	(247)	(259)	(316)	(371)	(209)
	19,191	17,110	16,273	18,102	16,342
Provision for (Recovery of) Income Taxes					
Current	8	20	21	67	98
Future	3	(103)	0	(85)	85
	11	(83)	21	(18)	183
Net Income	\$20,640	\$18,965	\$18,390	\$15,297	\$7,076
Funds from Operations, Before Working Capital Changes					
	\$30,978	\$29,194	\$28,724	\$27,420	\$19,531
per unit	\$1.01	\$0.95	\$0.93	\$0.89	\$0.63
Cash from Operations	\$31,995	\$23,135	\$29,270	\$27,421	\$17,973
per unit	\$1.04	\$0.75	\$0.95	\$0.89	\$0.58
Distributions to Unitholders	\$30,207	\$28,974	\$28,666	\$27,125	\$18,494
per unit	\$0.98	\$0.94	\$0.93	\$0.88	\$0.60

† nine months



* nine months

**Corporate
and Unitholder
Information**

Principal Office

c/o Iroquois Falls Power Management Inc.
30 St. Clair Avenue West
17th Floor
Toronto, Ontario M4V 3A2

Trustee

Montreal Trust Company of Canada
100 University Avenue
Toronto, Ontario M5J 2Y1
Attention: Corporate Services

Directors & Officers of
Iroquois Falls Power Corp.

James C. Temerty

President and Director
President, Iroquois Falls Power
Management Inc.
and Northland Power Inc.

Anthony F. Anderson

Chief Financial Officer
Chief Financial Officer, Iroquois Falls Power
Management Inc.
and Northland Power Inc.

Pierre R. Gloutney *

Director
President and Chief Executive Officer
Refco Futures (Canada) Ltd.

A. Warren Moysey *

Director
Director and Vice-Chairman,
CGU Canada Ltd.

The Right Honourable

John N. Turner, Q.C.

Director
Partner, Miller Thomson LLP

F. David Rounthwaite *

Director
Partner, McCarthy Tétrault LLP

Linda L. Bertoldi

Secretary
Partner, Borden Ladner Gervais LLP

Legal Counsel

Borden Ladner Gervais LLP
Toronto, Ontario

Auditors

Ernst & Young LLP
Toronto, Ontario

Bank

Canadian Imperial Bank of Commerce
Commerce Court West
Toronto, Ontario

Registrar & Transfer Agent

Computershare Trust Company of Canada
100 University Avenue
Toronto, Ontario M5J 2Y1
Attention: Equity Services

Trust Units

The trust units are listed on
The Toronto Stock Exchange
and trade under the symbol
NPI.UN.

* Member of the Audit Committee

Annual Meeting Date and Place

The fifth annual meeting of unitholders of
Northland Power Income Fund will be
held on *Thursday, May 23, 2002*, at 11:00 a.m.
in the TSE Conference Centre, located at
the Exchange Tower, 130 King Street West
(corner of King & York Streets),
Toronto, Ontario.

For investor information, please contact:

Barbara Bokla
Iroquois Falls Power Management Inc.
30 St. Clair Avenue West
17th Floor
Toronto, Ontario M4V 3A2

Telephone: 416-962-6262, Extension 156

Facsimile: 416-962-6266

E-mail: info@NPIFund.com

Web site: NPIFund.com

NORTHLAND POWER INCOME FUND

Glossary of Terms

Abitibi	Abitibi-Consolidated Company of Canada
DRIP	Northland Power Income Fund Distribution Reinvestment Plan
Facility	Plant located in Iroquois Falls, Ontario
Fund	Northland Power Income Fund
GJ	Gigajoules
IFPC	Iroquois Falls Power Corp.
IMO	Independent Electricity Market Operator
kWh	Kilowatt hour
M	Million
MW	Megawatt
MWh	Megawatt hour
Manager	Iroquois Falls Power Management Inc.
OEFC	Ontario Electricity Financial Corporation



NPIFund.com

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