QuickLinks -- Click here to rapidly navigate through this document

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended DECEMBER 31, 2000

OR

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

For the transition period from _______ to ________

Commission File Number: 1-10934

LAKEHEAD PIPE LINE PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**39-1715850** (I.R.S. Employer Identification No.)

Lake Superior Place
21 West Superior Street
Duluth, Minnesota 55802-2067
(Address of principal executive offices and zip code)

(218) 725-0100
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Class A Common Units	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes /x/ No / /

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes /x/ No / /

As of March 1, 2001, the aggregate market value of the Registrant's Class A Common Units held by non affiliates of the Registrant was $1,115,053,800 based on the reported closing sale price of such units on the New York Stock Exchange on that date.

As of March 1, 2001, there were 24,990,000 of the Registrant's Class A Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

TABLE OF CONTENTS

This Annual Report on Form 10-K contains forward-looking statements. These statements are based on the Partnership's beliefs as well as assumptions made by and information currently available to the Partnership. When used in this document, the words "anticipate," "believe," "expect," "estimate," "forecast," "project," and similar expressions identify forward-looking statements. These statements reflect the Partnership's current views with respect to future events and are subject to various risks, uncertainties and assumptions including:

- *the Partnership's dependence upon adequate supplies of and demand for western Canadian crude oil,*
- *the Partnership's ability to acquire other companies and assets,*
- *the price of crude oil and the willingness of shippers to ship crude oil,*
- *regulation of the Partnership's tariffs by the Federal Energy Regulatory Commission and the possibility of unfavorable outcomes of future tariff proceedings, and*
- *the effects of competition, in particular, by other pipeline systems.*

If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, actual results may vary materially from those described in this Form 10-K. Except as required by applicable securities laws, the Partnership does not intend to update these forward-looking statements. For additional discussion of such risks, uncertainties and assumptions, see "Items 1 & 2. Business and Properties—Risk Factors" included elsewhere in this Form 10-K.

PART I

Items 1 & 2. Business and Properties

Overview

Lakehead Pipe Line Partners, L.P. ("Registrant" or "Partnership") is a publicly traded Delaware limited partnership, which owns a 99%

limited partner interest in Lakehead Pipe Line Company, Limited Partnership ("Operating Partnership"), also a Delaware limited partnership. Unless the context otherwise requires, references in this Form 10-K to the Partnership include the Registrant and the Operating Partnership.

The Partnership was formed in 1991 to acquire, own and operate the regulated crude oil and natural gas liquids pipeline business of Lakehead Pipe Line Company, Inc. ("General Partner"), a wholly-owned subsidiary of Enbridge Pipelines Inc. ("Enbridge Pipelines"). Enbridge Pipelines is a Canadian company owned by Enbridge Inc. ("Enbridge") of Calgary, Alberta, Canada. The General Partner owns a 13.4% limited partner interest (in the form of 3,912,750 Class B Common Units) and a 1% general partner interest in the Registrant, as well as a 1% general partner interest in the Operating Partnership (an effective 15.3% combined interest in the Partnership). The remaining 84.7% limited partner interest in the Partnership is represented by 24,990,000 publicly traded Class A Common Units.

The Partnership and Enbridge Pipelines transport crude oil and other liquid hydrocarbons for others through the world's longest liquid petroleum pipeline system ("System"). The System is the primary transporter of crude oil from western Canada to the United States and is the only pipeline that transports crude oil from western Canada to the province of Ontario, Canada. The System serves all the major refining centers in the Great Lakes region of the United States, as well as Ontario and the Patoka/Wood River pipeline hub and refining center in southern Illinois. Enbridge Pipelines owns the Canadian portion of the System ("Enbridge Pipelines System") and the Partnership owns the U.S. portion of the System ("Lakehead System").

The System extends from Edmonton, Alberta, across the Canadian prairies to the U.S. border near Neche, North Dakota. From Neche the System continues on to Superior, Wisconsin, where it splits into two branches with one branch travelling through the upper Great Lakes region and the other through the lower Great Lakes region of the United States. Both branches reenter Canada near Marysville, Michigan. From Marysville the System continues on to Toronto, Ontario and Montreal, Quebec, with lateral lines to Nanticoke, Ontario and the Buffalo, New York area. The System is approximately 3,100 miles long, of which approximately 1,880 are in the United States.

Shipments tendered to the System primarily originate in oil fields in the western Canadian provinces of Alberta, Saskatchewan, Manitoba and British Columbia and in the Northwest Territories of Canada and reach the System through facilities owned and operated by third parties or affiliates of Enbridge Pipelines. Deliveries from the System are currently made in the prairie provinces of Canada and through the Lakehead System, to the Great Lakes and Midwest regions of the United States and to the Province of Ontario. These deliveries are made principally to refineries either directly or through connecting pipelines of other companies.

All scheduling of shipments (including routes and storage) is handled by Enbridge Pipelines in coordination with the Partnership. The Lakehead System includes 15 connections to pipelines and refineries at various locations in the United States, including the refining areas in and around Chicago, Illinois, Minneapolis-St. Paul, Minnesota, Detroit, Michigan, Toledo, Ohio, Buffalo and Patoka/Wood River. The Lakehead System has three main terminals at Clearbrook, Minnesota, Superior, Wisconsin and Griffith, Indiana. The terminals are used to gather crude oil prior to injection into the Lakehead System and to provide tankage in order to allow for more flexible scheduling of oil movements.

Properties

The Lakehead System consists of approximately 3,300 miles of pipe with diameters ranging from 12 inches to 48 inches, 63 main line pump station locations with a total of approximately 667,000 installed horsepower and 58 crude oil storage tanks with an aggregate working capacity of approximately 10 million barrels. The volume of liquid hydrocarbons in the Lakehead System required at all times for operation is approximately 14 million barrels, all of which is owned by the shippers on the Lakehead System. The Lakehead System regularly transports up to 45 different types of liquid hydrocarbons including light, medium and heavy crude oil (including bitumen), condensate, synthetic crudes and natural gas liquids ("NGL").

The Lakehead System is comprised of a number of separate segments as follows:

- Canadian border to Clearbrook segment including portions of four pipelines consisting of 18-, 20-, 26-, and 34-inch diameter pipe, respectively, and a fifth line consisting of 36- and 48-inch diameter pipe with a total annual capacity of 1,727,000 barrels per day;
- Clearbrook to Superior segment including portions of three pipelines consisting of 18-, 26-, and 34-inch diameter pipe, respectively, with a total annual capacity of 1,464,000 barrels per day. This segment includes approximately 80 miles of 48-inch pipeline looping that increases the capacity of this segment;
- Superior to Marysville segment consisting of 30-inch diameter pipe with an annual capacity of 509,000 barrels per day;
- Superior to Chicago area segment including two pipelines of 24- and 34-inch diameter pipe with a total annual capacity of 889,000 barrels per day;
-

- Chicago area to Marysville segment consisting of a 30-inch diameter pipe with an annual capacity of 333,000 barrels per day; and

- Canadian border to Buffalo segment consisting of 12- and 20-inch diameter pipe with an annual capacity of 74,000 barrels per day.

Estimated annual capacities noted above take into account receipt and delivery patterns and ongoing pipeline maintenance, and reflect achievable pipeline capacity over long periods of time.

The Partnership believes that the Lakehead System has been constructed and is maintained substantially in accordance with applicable federal, state and local laws and regulations, standards prescribed by the American Petroleum Institute and accepted industry practice. The Partnership attempts to control corrosion of the pipeline through the use of pipe coatings and cathodic protection systems and monitors the integrity of the Lakehead System through a program of periodic internal inspections using electronic instruments. At intervals not exceeding 3 weeks, but at least 26 times each calendar year, the entire pipeline right of way is inspected from the air. In addition, trained and skilled operators use computerized monitoring systems to identify pressure drops that might indicate potential disruptions in flow, and operate remote controlled valves and pumps that allow the Lakehead System to be shut down quickly if required.

Title to Properties

The Partnership conducts business and owns properties located in seven states. In general, the Lakehead System is located on land owned by others and is operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities.

The pumping stations, tanks, terminals and certain other facilities of the Lakehead System are located on land that is owned by the Partnership, except for five pumping stations that are situated on

land owned by others and occupied by the Partnership, pursuant to easements or permits. An affiliate of the General Partner acquired parcels of property for the benefit of the Partnership to allow for the construction of the System Expansion Program II ("SEP II"). The affiliate is in the process of selling these parcels to third parties while retaining an easement for the benefit of the Partnership. See "Item 13. Certain Relationships and Related Transactions." Substantially all of the Lakehead System assets are subject to a first mortgage securing indebtedness of the Operating Partnership.

Risk Factors

The Lakehead System is dependent upon the level of supply of crude oil and other liquid hydrocarbons from western Canada. In 1999 and 2000, the Partnership's crude oil deliveries declined compared with 1998. This decline resulted primarily from decreased crude oil production in western Canada, which in turn resulted primarily from reduced spending levels for exploration and development activities in western Canada and a focus on natural gas drilling rather than oil. These reduced spending levels resulted from low oil prices in 1998 and the first part of 1999. The Partnership's ability to increase deliveries and to expand the Lakehead System in the future also depend upon increased supplies of western Canadian crude oil. For a discussion of the forecast for the future supply of crude oil produced in western Canada. See "—Supply of and Demand for Western Canadian Crude Oil."

Demand for western Canadian crude oil and NGL in the geographic areas served by the Lakehead System is affected by the delivery of other crude oil and refined products into the same areas. Existing pipeline capacity for the delivery of crude oil to the U.S. Midwest, the primary destination market served by the Lakehead System, exceeds current refining capacity. The Partnership believes that the System has several advantages over other transporters of crude oil with which it competes and the System is among the lowest cost transporters of crude oil and NGL in North America based on costs per barrel mile transported. See "—Competition."

The Enbridge Pipelines System includes a section that extends from Sarnia, Ontario to Montreal, Quebec ("Line 9") which, at one time, flowed in a west-to-east direction. During 1999, Enbridge Pipelines and a group of refiners reversed the flow of Line 9. Consequently, crude oil is now imported into the province of Quebec, Canada from foreign sources through the facilities of Portland Pipe Line Corporation, Montreal Pipe Line Limited and Enbridge Pipelines. This offshore crude oil supply has resulted in a decrease in the Partnership's level of deliveries into the Ontario market. However, the Partnership expects that this decrease will be offset by an increase in deliveries to the Chicago area and other markets it serves.

The Partnership is subject to the risk that changes may occur in existing economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices. Any of these factors could reduce the demand for crude oil and other liquid hydrocarbons in the areas in which deliveries are made by the Lakehead System. In addition, reduced throughput on the System could result from testing, line repair, reduced operating pressures, reduced crude oil supply, regulatory restrictions on System utilization or other causes.

The operations of the Partnership are subject to federal and state laws and regulations relating to environmental protection and operational safety. Although the Partnership believes that the operations of the Lakehead System are essentially in compliance with applicable environmental and safety regulations, risks of substantial costs and liabilities are inherent in pipeline operations, and there can be no assurance that such costs and liabilities will not be incurred. See "—Environmental and Safety Regulation."

The Partnership periodically files tariff rate increases and decreases with the Federal Energy Regulatory Commission ("FERC"). A tariff agreement between the Partnership and customer representatives sets forth parameters governing the tariff changes associated with SEP II, Terrace, and

other expansion projects. Notwithstanding this agreement, any shipper who is not a party to the agreement could challenge any existing or future rate filings. Any challenge, if successful, could have a material adverse effect on the Partnership. For a discussion of FERC regulation, Partnership tariff rates and the tariff agreement, see "—Regulation" and "—Tariffs."

The Partnership's ability to increase earnings and cash distributions will depend, in part, upon the ability to identify and complete acquisition opportunities. Growth through acquisitions, and the future operating results and success of such acquisitions, may be subject to the effects of, and changes in laws and regulations, political and economic developments, inflation rates, taxes, financing capability and operating conditions.

Regulation

FERC Regulation

The Partnership's interstate common carrier pipeline operations are subject to rate regulation by the FERC under the version of the Interstate Commerce Act ("ICA") applicable to oil pipelines. The ICA requires that petroleum products and crude oil pipeline rates be just, reasonable and non-discriminatory. The ICA permits challenges to new, changed and existing rates through either a "protest" or "complaint." At the FERC, a protest normally applies only to a proposed change in a pipeline's rates or practices and subjects the pipeline to a forward-looking investigation and possible refund obligation. The FERC can also choose to suspend the proposed change for up to seven months from the proposed date of the change. A complaint, by comparison, typically applies to an existing rate or practice and subjects the pipeline, in certain circumstances, to possible two year retroactive liability for past rates or practices found to be unlawful.

The FERC utilizes a simplified ratemaking methodology for oil pipelines that prescribes an indexing methodology for setting rate ceilings. As described in FERC Orders No. 561 and No. 561-A, the index used is the Producer Price Index for Finished Goods minus 1% ("PPIFG-1"). Rate ceiling levels are increased or decreased each July 1. The PPIFG-1 index for use beginning on July 1, 2000, was approximately 0.8%. Inflationary rate changes prescribed under the FERC's indexing methodology may be different than changes in the Partnership's costs. Indexed rates are subject both to protests and to complaints, but in either case the FERC's existing regulations specify that the party challenging a rate must show reasonable grounds for asserting that the amount of any rate increase resulting from application of the index is so substantially in excess of the pipeline's increase in costs as to be unjust and unreasonable (or that the amount of any rate decrease is so substantially less than the actual cost decrease incurred by the pipeline that the rate is unjust and unreasonable).

The FERC has stated that, as a general rule, pipelines must utilize the indexing methodology to change rates. However, the FERC has retained cost-based ratemaking, market-based rates and settlements as alternatives to the indexing approach. A pipeline can follow a cost-based approach when it can demonstrate that there is a substantial divergence between the actual costs experienced by the carrier and the rates resulting from application of the index. Under FERC's cost-based methodology, crude oil pipeline rates are permitted to generate operating revenues, based on projected volumes, not greater than the total of operating expenses, depreciation and amortization, federal and state income taxes and an overall allowed rate of return on the pipeline's rate base. In addition, a pipeline can charge market-based rates if it first establishes that it lacks significant market power in a particular relevant market, and a pipeline can establish rates pursuant to a settlement if agreed upon by all current shippers. Initial rates for new services can be established through a cost-based filing or through an uncontested agreement between the pipeline and at least one shipper not affiliated with the pipeline.

Other Regulation

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment with respect to the passage of oil and gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

Tariffs

Rate Cases

The Partnership had several rate cases pending before the FERC during the period from 1992 to 1996. The primary issue was the applicability of the FERC's Opinion 154-B/C trended original cost methodology. In 1995 and 1996, the FERC issued decisions on the Partnership's 1992 tariff rate increase that determined the Partnership was entitled to use the FERC's Opinion No. 154-B/C rate methodology, although it was not entitled to recover in its cost of service a tax allowance with respect to income attributable to limited partners who are not corporations or other similar entities.

In October 1996, the FERC approved a settlement agreement ("Settlement Agreement") between the Partnership, the Canadian Association of Petroleum Producers ("CAPP") and the Alberta Department of Energy ("ADOE") on all then-outstanding contested tariff rates. The Settlement Agreement provided for a tariff rate reduction of approximately 6% and total rate refunds and interest of $120.0 million through the effective date of October 1, 1996, with interest accruing thereafter on the unpaid balance. The Partnership made rate refunds of $41.8 million in the fourth quarter of 1996, with the balance being paid through a 10% reduction of tariff rates until all refunds were made. Effective November 22, 1999, the 10% reduction in tariff rates was removed and the $120.0 million refund and related interest were fully repaid.

The Settlement Agreement also provided for the terms of an incremental tariff rate surcharge for a period of 15 years to recover the cost of, and allow a return on, the Partnership's investment in SEP II. The rate of return on this investment will be based, in part, on the utilization level of the additional capacity constructed. As specified in the Settlement Agreement, higher utilization will result in a greater rate of return, subject to a minimum and maximum rate of return of 7.5% and 15.0%, respectively. The tariff rate surcharge will be recomputed on a cost of service basis and filed with FERC each year. The Settlement Agreement provided that the agreed underlying tariff rates will be subject to indexing as prescribed by FERC regulation and that CAPP and ADOE will not challenge any rates within the indexed ceiling for a period of five years, expiring October 2001. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, —Future Prospects, —Regulatory Issues."

Tariff Agreement

In 1998, the Partnership filed an offer of settlement ("Tariff Agreement") with the FERC to facilitate the filing of tariff rate surcharges in late 1998 and early 1999. This filing consolidated the 1996 Settlement Agreement with respect to SEP II and other significant agreements with customers concerning the Terrace Expansion Program ("Terrace") and the transportation of heavy crude oil. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, —Future Prospects, —Lakehead System Growth, —Projects Recently Completed or Under Development." The FERC found the Tariff Agreement a reasonable compromise and approved it on the grounds that it is fair, reasonable, and in the public interest.

With respect to Terrace, the Tariff Agreement included terms governing a tariff surcharge associated with the project. A fixed toll increase of Cdn. $0.05 per barrel for the movement of light

crude oil from Edmonton to the Chicago area is allocated approximately Cdn. $0.02 ($0.013 U.S.) to the Partnership and Cdn. $0.03 to Enbridge Pipelines. Effective April 1, 2001, Enbridge and the Partnership agreed to reallocate the Cdn. $0.05 per barrel Terrace toll surcharge, Cdn. $0.04 ($0.026 U.S.) to the Partnership and Cdn. $0.01 to Enbridge. This reallocation is permitted under the terms of the Agreement and was done in an effort to rebalance the project economics between the parties as a result of volume shortfalls, for which the Partnership is completely at risk. The toll increase is also subject to increase or decrease based on changes in other defined circumstances. The portion of the agreement associated with Terrace also establishes in-service and notice dates for future phases of the expansion program. Should CAPP not provide notice to construct later phases of Terrace by July 1, 2001, the toll increment will revert to a cost of service recovery, including collection of both prospective and past variances between revenue generated by the Cdn. $0.05 toll increment and the Terrace cost of service. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations,—Future Prospects, —Lakehead System Growth—Projects Recently Completed or Under Development."

Other Pipeline Rate Cases

On January 13, 1999, the FERC issued an opinion and order in a case involving Santa Fe Pacific Pipelines, L.P. ("SFPP") ("Opinion No. 435"), which addressed various issues of interest to FERC-regulated publicly traded partnerships and other oil pipelines. These included application of FERC's Opinion No. 154-B/C rate methodology and income tax allowances for publicly traded partnerships. On May 17, 2000, the FERC issued an order on rehearing ("Opinion No. 435-A") that largely reconfirmed the rulings in Opinion No. 435. This order is subject to further rehearing on certain issues, as well as judicial review. The SFPP opinion is not anticipated to have an impact on the Partnership's current rates due to the Tariff Agreement with customers. If the SFPP opinion is not changed on further rehearing by FERC or on review by a court of appeals, and if it were applied to the Partnership in some future rate proceedings, the impact to the Partnership, positive or negative, would be dependent upon the specific application of the rulings in that opinion to the Partnership.

Many of the ratemaking issues contested in the Partnership's rate cases, in particular the FERC's oil pipeline ratemaking methodology, have not been reviewed by a federal appellate court. Judicial review (whether or not in a case directly involving the Partnership) could ultimately result in the implementation of alternative ratemaking methodologies that could have a material adverse effect on the Partnership.

Tariffs

Under published tariffs for transportation by the Lakehead System, the rates for light crude oil from key receipt locations to principal delivery points at January 1, 2001 (including the tariff surcharges related to SEP II and Terrace) are set forth below.

	Published Tariff Per Barrel
Canadian border near Neche to Clearbrook	$ 0.163
Canadian border near Neche to Superior	$ 0.316
Canadian border near Neche to Chicago area	$ 0.642
Canadian border near Neche to Marysville area	$ 0.767
Canadian border near Neche to Buffalo area	$ 0.785
Chicago to the international border near Marysville	$ 0.286

The rates at January 1, 2001, for medium and heavy crude oils are higher, while those for NGL are lower, than the rates set forth in the table to compensate for differences in costs for shipping

different types and grades of liquid hydrocarbons. The Partnership periodically adjusts its tariff rates as allowed under FERC's indexing methodology and the Tariff Agreement, and will file an updated SEP II surcharge to be effective April 1, 2001. This filing will include any differences between the SEP II surcharge filed in 2000 and actual results for the year, as well as an estimate for 2001. Overall, the surcharge should remain relatively consistent with 2000 levels.

Deliveries from the Lakehead System

Deliveries from the Lakehead System are made in the Great Lakes and Midwest regions of the United States and in Ontario, principally to refineries, either directly or through connecting pipelines of other companies. Major refining centers within these regions are located near Sarnia, Ontario, Nanticoke, Toronto, Minneapolis-St. Paul, Superior, Chicago, the Patoka/Wood River area, Detroit, Toledo, and Buffalo areas. Crude oil and NGL transported by the Lakehead System are feedstock for refineries and petrochemical plants.

The U.S. government segregates the United States into five districts, Petroleum Administration for Defense Districts ("PADD"), for purposes of its strategic planning to ensure crude oil supply to key refining areas in the event of a national emergency. The oil industry utilizes these districts in reporting statistics regarding oil supply and demand. The Lakehead System services the northern tier of PADD 2. U.S. governmental publications project that crude oil demand in this area will remain relatively constant over the next 10 years. In addition, these publications project the total supply of crude oil from producing areas in the U.S. southwest, Rocky Mountains and Midwest that currently serve the entire PADD 2 market, to decline in the near term as reserves are depleted, resulting in a need for additional supplies of crude oil to replace the continuing demand. As a result of these factors, the Partnership believes that the Lakehead System will be able to exceed its current level of deliveries into PADD 2 during the next 10 years.

The following table sets forth Lakehead System average deliveries per day and barrel miles for each of the years in the five-year period ended December 31, 2000.

	Deliveries				
	2000	1999	1998	1997	1996
	(thousands of barrels per day)				
United States					
Light crude oil	321	299	338	282	309
Medium and heavy crude oil	630	575	627	652	569
NGL	25	24	27	26	23
Total United States	976	898	992	960	901
Ontario					
Light crude oil	174	282	366	355	348
Medium and heavy crude oil	85	87	97	98	102
NGL	103	102	107	99	100
Total Ontario	362	471	570	552	550
Total Deliveries	1,338	1,369	1,562	1,512	1,451
Barrel miles (billions per year)	341	350	391	389	384

Supply of and Demand for Western Canadian Crude Oil

Supply

Substantially all of the shipments delivered through the Lakehead System originate in oilfields in western Canada. The Lakehead System also receives U.S. and Canadian production at Clearbrook through a connection with a pipeline owned by a subsidiary of Enbridge, U.S. production at Lewiston, Michigan, and both U.S. and offshore production in the Chicago area. Changes in supply from western Canada directly affect movements through the Enbridge Pipelines System and, therefore, the supply available for transportation through the Lakehead System. Due to the integration of the Enbridge and Lakehead Systems, Enbridge Pipelines regularly prepares forecasts of western Canadian crude oil, which take into account deliveries on the Lakehead System.

The low crude oil prices experienced during 1998 and early 1999 caused a decline in western Canadian producers' expenditures for oil exploration and development, which in turn adversely affected the crude oil supply available in western Canada. As a result, Enbridge Pipelines has updated its forecast of western Canadian crude oil supply and the markets served by the System. This long-term outlook involves updated supply projections from the oil sands projects currently operating, being expanded or proposed in western Canada. The Partnership believes that production from these projects is less sensitive to the short-term fluctuations in the price of crude oil due to the magnitude of committed capital expenditures involved.

The updated Enbridge Pipelines forecast projects that the supply of western Canadian crude oil will be approximately 2,150,000 barrels per day in 2001 and approximately 2,300,000 barrels per day in 2002. This updated forecast projects the supply of crude oil to rise to approximately 2,500,000 barrels per day in 2003 and to approximately 2,940,000 barrels per day by 2010. The forecast quantity of crude oil was made subject to numerous uncertainties and assumptions, including a crude oil price of $21.95 per barrel in 2000 rising to $27.00 in 2010. On December 29, 2000, the benchmark West Texas Intermediate crude oil price closed at $26.70 per barrel.

While the projected supply of crude oil for 2001 and 2002 is lower than the forecast that supported the Terrace Expansion Project, the updated Enbridge Pipelines forecast supports the need for additional pipeline facilities beyond the Terrace Phase I facilities. Phase II includes construction of facilities to increase capacity on the Canadian portion of the System. While Phase II does not involve construction on the Lakehead System, the Partnership expects to benefit directly from the approximately 40,000 barrels per day increase in capacity as additional volumes from the Alberta Oil Sands come on stream. Subject to final National Energy Board ("NEB") approval, Phase II is expected to be placed in service during 2002.

The NEB had previously released a report titled "*Canadian Energy Supply and Demand to 2025*" on June 30, 1999, in which it provided several scenarios of supply and demand for western Canadian crude oil. The most realistic scenario from the Partnership's perspective is a case that is based on a WTI price of $18.00 per barrel in constant 1997 dollars and assumes low cost energy supply and current trends in demand. This scenario resulted in total western Canadian production that was modestly lower than the Enbridge Pipelines most recent forecast by approximately 100,000 barrels per day in 2005. CAPP had also previously released its forecast of western Canadian crude oil production on May 18, 1999. The Enbridge forecast is higher than the CAPP forecast by about 70,000 bpd in 2005.

The Partnership believes that the outlook for increased crude oil production in western Canada continues to be positive, as evidenced by the Enbridge Pipelines forecast, the NEB study and CAPP's recent request to proceed with Terrace Phase II. The timing of growth in the supply of western Canadian crude oil, however, will depend upon the level of crude oil prices, oil and drilling activity and the timing of completion of projects to produce heavy and synthetic oil from the Alberta Oil Sands. It

is anticipated that 2001 deliveries on the Lakehead System will be approximately 1,400,000 to 1,450,000 barrels per day based on a recent survey of shippers.

Demand

The Partnership believes that modestly increasing crude oil demand and declining inland U.S. domestic production are contributing to an increasing need for importing crude oil into the PADD 2 market. The Partnership also believes that PADD 2 will continue to provide an excellent market for western Canadian shippers as returns to crude oil producers are expected to remain attractive. Moreover, the Partnership believes that PADD 2 will remain the most attractive market for western Canadian supply since it is currently the largest North American processor of western Canadian heavy crude oil and has the greatest potential for converting refining capacity from light to heavy crude.

Although western Canadian producers experience competition from Venezuelan and Mexican heavy crude oil in PADD 2, western Canadian heavy crude oil is expected to remain the dominant supply source for the region. The Partnership believes that Latin American heavy crude oil will continue to provide the balancing supply to the PADD 2 region. In the short-term, Latin American deliveries to PADD 2 are expected to decrease as the supply of western Canadian crude oil continues to recover from the negative impact of the 1998/99 price decline. Over the long-term, it is expected that producers of Latin American heavy crude oil will concentrate on PADD 3 and PADD 5 markets, where they receive a higher return compared to PADD 2.

Based on the most recent forecast completed by Enbridge Pipelines, exports from western Canada to the United States are forecast to increase to approximately 1,835,000 barrels per day in 2005 and remain at that level or above through 2010. This is approximately 700,000 barrels per day higher than 1999 exports. Of the exports to the United States, PADD 2 would receive approximately 1,365,000 barrels per day in 2005, approximately 500,000 barrels per day higher than 1999.

Deliveries to Ontario averaged approximately 362,000 barrels per day in 2000. Demand in Ontario is expected to grow to approximately 640,000 barrels per day over the next several years. Since 1999, Partnership deliveries to Ontario have been impacted by the reversal of Enbridge Line 9 from Montreal to Sarnia. Based on the Partnership's forecast, and assuming no expansion of Line 9, Partnership deliveries to Ontario are expected to approximate 2000 levels in 2001 and grow modestly thereafter.

Crude oil refineries in Ontario generally process light sweet and light sour crude oil, and the supply of conventional light sweet and light sour crude oil in western Canada is expected to decline. Ontario refiners cannot process significantly greater amounts of western Canadian heavy crude oil without substantial reconfiguration of their refineries. To the extent Ontario refiners have found it difficult to obtain light crude oil supply from western Canada at an economic price, refiners have been recently accessing foreign light crude volumes through the reversed facilities of Line 9. This has had an impact on the volumes moving through the Lakehead System pipeline connections in the Chicago area. Light crude oil movements originating in the Chicago area for delivery to Ontario declined following the reversal of Enbridge's Line 9 in 1999, averaging approximately 63,500 barrels per day for 1999, and approximately 15,000 barrels per day in 2000. Line 9 has an annual capacity of approximately 240,000 barrels per day and, in 2000, operated at approximately 210,000 barrels per day. The ongoing utilization level of Line 9 will be dependent upon global crude oil market dynamics.

Customers

The Lakehead System operates under month-to-month transportation arrangements with its shippers. During 2000, 47 shippers tendered crude oil and NGL for delivery through the Lakehead System. These customers included integrated oil companies with production facilities in western Canada and refineries in Ontario, major oil companies, refiners and marketers. Shipments by the top ten shippers during 2000 accounted for approximately 87% of total revenues during that period. Revenue

from BP Amoco (through affiliated companies), Mobil Oil Company of Canada Ltd. and PDV Midwest accounted for approximately 25%, 16% and 11%, respectively, of total operating revenue generated by the Lakehead System during 2000. The remaining shippers each accounted for less than 10% of total revenues. See Note 8 to the Partnership's Consolidated Financial Statements.

Capital Expenditures

In 2000, the Partnership made capital expenditures of $21.7 million, of which $10.9 million was for core maintenance and $10.8 million for pipeline system enhancements. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Taxation

For federal and state income tax purposes, the Partnership and Operating Partnership are not taxable entities. Federal and state income taxes on Partnership taxable income are borne by the individual partners through the allocation of Partnership taxable income. Such taxable income may vary substantially from net income reported in the statement of income.

Competition

Because pipelines are the lowest cost method for intermediate and long haul movement of crude oil over land, the System's most significant existing competitors for the transportation of western Canadian crude oil are other pipelines. In 2000, the Enbridge Pipelines System transported approximately 65% of total western Canadian crude oil production, of which approximately 90% was transported by the Lakehead System. The remainder of 2000 western Canadian crude oil production was refined in Alberta or Saskatchewan or transported through other pipelines. Of the pipelines transporting western Canadian crude oil out of Canada, the System provides approximately 75% of the total pipeline design capacity. The remaining 25% of design capacity is shared by five other pipelines transporting crude oil to British Columbia, Washington, Montana and other states in the U.S. Northwest.

Competition among common carrier pipelines is based primarily on transportation charges, access to producing areas and proximity to end users. The Partnership believes that high capital requirements, environmental considerations and the difficulty in acquiring rights of way and related permits make it difficult for a competing pipeline system comparable in size and scope to the System to be built in the foreseeable future.

Express Pipeline Ltd. ("Express Pipeline") owns and operates a 170,000 barrel per day capacity pipeline that carries western Canadian crude oil to the U.S. Rocky Mountain region, where it connects to a 150,000 barrels per day capacity pipeline system. This connecting pipeline serves the Patoka/Wood River market area. The Express Pipeline began service in early 1997. The System, however, offers lower tolls into Chicago and Patoka and competitive tolls into Wood River and, furthermore, the System does not require shipper volume commitments as currently required by Express Pipeline.

The System encounters competition in serving shippers to the extent that shippers have alternative opportunities for transporting liquid hydrocarbons from their sources to customers. In selecting the destination for their supplies of crude oil, sellers generally desire to use the alternative that results in the highest return to them. Generally, it is expected that sellers will receive the highest return from markets served by the System, but alternate markets may, for periods of time, offer equal or better returns for the seller. Such markets could potentially include the U.S. Rocky Mountain region for sweet crude oil and the Washington State market for light sour crude oil.

In the United States, the Lakehead System encounters competition from other crude oil and refined product pipelines and other modes of transportation delivering crude oil and refined products

to the refining centers of Minneapolis-St. Paul, Chicago, Detroit and Toledo and the refinery market and pipeline hub located in the Patoka/Wood River area. The Lakehead System transports approximately 50% of all crude oil deliveries into the Chicago area, approximately 80% of all crude oil deliveries into the Minneapolis-St. Paul area and approximately 55% of all deliveries of crude oil to Ontario and Buffalo.

Environmental and Safety Regulation

General

The operations of the Partnership are subject to federal, state and local laws and regulations relating to protection of the environment and safety. Although the Partnership believes that the operations of the Lakehead System are in substantial compliance with applicable environmental and safety laws and regulations, the risk of substantial liabilities is inherent in pipeline operations, and there can be no assurance that substantial liabilities will not be incurred. To the extent that the Partnership is unable to recover environmental costs in its rates (if not recovered through insurance), the Partnership could be subject to material costs.

In general, the Partnership expects to incur future ongoing expenditures to comply with industry and regulatory environment and safety standards. The Partnership does not expect that such expenditures, to the extent they can be estimated, will have a material adverse effect on the Partnership.

Air

The operations of the Partnership are subject to the federal Clean Air Act ("CAA") and comparable state statutes. Expenses of routine compliance with these and other similar regulations are not expected to have a material adverse impact on the Partnership.

Water

The federal Clean Water Act ("CWA") as amended, imposes strict controls on the discharge of any pollutant, including oil, into the waters of the United States. The CWA provides penalties for any such discharge, imposes liability for clean-up costs and natural resource damage, and allows for third party lawsuits. As required by the CWA, the Partnership has developed Facility Response Plans, which are designed to prevent contamination of waters in the event of a petroleum overflow, rupture or leak, and has submitted these plans to, and received the approval of, the Office of Pipeline Safety ("OPS") of the U.S. Department of Transportation ("DOT"). The federal Safe Drinking Water Act of 1974, as amended, further regulates discharges into groundwater. State laws also provide varying civil and criminal penalties and liabilities in the case of a release of pollutants into surface water or groundwater. Expenses of routine compliance with these and other similar regulations are not expected to have a material adverse impact on the Partnership.

Remediation Matters

Contamination resulting from spills of crude oil and petroleum products is not unusual within the petroleum pipeline industry. Historic spills along the Lakehead System as a result of past operations may have resulted in soil or groundwater contamination. The Partnership is addressing known sites through monitoring and remediation programs. Currently, expenses relating to such remediation programs are not expected to have a material adverse impact on the Partnership.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act of 1989 ("CERCLA"), as amended, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original act, on certain classes of persons that contribute to the release of a "hazardous substance" into the environment. In the course of its ordinary operations, the Lakehead System generates wastes, some of which fall within the federal and state statutory definitions of a "hazardous substance" and some of which were historically disposed of at sites that may require cleanup under Superfund and related state statutes. The Partnership is unaware of any such obligations at this time.

Waste

The Partnership generates hazardous and non-hazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The Partnership believes that operations of the Lakehead System are in substantial compliance with such statutes in all states in which it operates.

Safety Regulation

The Partnership's operations are subject to construction, operating and safety regulation under the Pipeline Safety Act ("Act") as applied by the DOT and OPS, as well as various other federal, state and local agencies. The Act has been amended periodically requiring OPS to consider environmental impacts and cost-benefit analysis, in addition to its traditional public safety considerations, when developing safety regulations. Among the amendments, OPS was mandated to establish pipeline operator qualification rules that were issued in 1999 and come into effect during 2001. Other requirements include mandating OPS to establish a national pipeline mapping and records system, evaluating the feasibility of requiring additional valves and/or remotely operated valves and completing the identification of areas "unusually environmentally sensitive" to leaks from liquid pipelines. In December 2000, the OPS issued final rules defining "unusually environmentally sensitive areas" following a comment period and pilot test. As well, in December 2000 OPS issued final rules for "Integrity Management Plans for Liquid Pipelines in High Consequence Areas" as well as proposed rules for more prescriptive corrosion protection standards. The Partnership has submitted pipeline maps and descriptive detail to OPS as part of their voluntary national mapping and records system now in progress. The recently issued rules or proposed rules are comprehensive, but are not expected to have a material adverse financial effect on the Partnership.

Following an unsuccessful legislative attempt to approve additional sweeping amendments of the Act during 2000, an Executive Memorandum was issued by the President. This Executive Memorandum directed OPS to evaluate their enforcement program and aggressively pursue safety mandates to require risk-based integrity management programs, broader external communication, and meaningful involvement of states in interstate pipeline safety. It also called for initiation of research and development programs, development of a definition for 'unusually sensitive areas', and reinforcement of a quick resolution of rules for increased corrosion protection.

These legislative and regulatory proposals are largely prompted by a significant incident in June 1999 on the Olympic Pipeline system in Bellingham, Washington and an August 2000 incident on the El Paso natural gas pipeline in New Mexico. The Partnership has been monitoring these proposals and will work closely with Congress and industry associations to advocate strong but cost-effective provisions. As this legislative initiative is still evolving, the financial impact of additional new regulations cannot be determined at this time. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, —Future Prospects, —New Safety Legislation."

Employees

Neither the General Partner nor the Partnership has any employees. The General Partner is responsible for the management and operation of the Partnership and to fulfill these obligations, it has entered into agreements with Enbridge and several of its subsidiaries to provide the necessary services. The Partnership reimburses service providers for expenses incurred in performing these services at cost.

Item 3. Legal Proceedings

The Partnership is a defendant in various lawsuits and a party to various legal proceedings arising in the ordinary course of business. Some of these lawsuits and proceedings are covered, in whole or in part, by insurance. The Partnership believes that the outcome of all of these matters will not, individually or in the aggregate, have a material adverse effect on the financial condition of the Partnership.

In 1998, directional drilling operations for SEP II construction caused discharges of non-hazardous bentonite drilling mud in a wetlands area. The Partnership and the State of Illinois subsequently entered into an agreement wherein the Partnership was released from liability resulting from the discharges in return for the transfer to the Illinois Department of Natural Resources ("DNR") of seven acres of the affected wetlands and payment to the State of $24,000. The agreement took effect in early 2000 and the Partnership has fulfilled its obligation under the agreement.

In a separate action related to the drilling discharges, the U.S. Environmental Protection Agency ("EPA") filed an administrative complaint against the Partnership in August 1999, seeking penalties for violations of the CWA resulting from the bentonite discharges into the wetlands. The Partnership and the EPA negotiated a Consent Order, pursuant to which the Partnership paid a civil penalty of approximately $14,000 and performed a Supplemental Environmental Project consisting of a contribution of approximately $46,000 to a conservation foundation in Illinois used to purchase twelve acres of environmentally sensitive property on the Fox River near Chicago. As part of the Project, the conservation foundation contributed this property to the Illinois DNR for management and preservation. The Partnership fulfilled its obligation under this agreement in early 2000.

In December 1999, the Partnership paid to the Illinois DNR a penalty of $98,000 and costs of $2,000 for a May 28, 1998 release of crude oil caused by a third party in Orland Park, Illinois. The Partnership, the third party and the Illinois Attorney General executed a Consent Order in November 1999. The Partnership initiated litigation against the third party to recoup the penalty and all other costs incurred by the Partnership in connection with the release. A settlement was reached in October 2000, wherein the Partnership recovered from the third party substantially all costs, including penalties and attorney fees, incurred in connection with the release and subsequent litigation.

The Partnership received a draft complaint on September 21, 1999, from the Department of Justice for the State of Wisconsin alleging violations of state pollution control regulations during construction on SEP II in the summer of 1998. The first violation alleged that the Partnership failed to monitor all discharges of water from SEP II construction trenches and, on certain occasions, exceeded the effluent limitations set forth in a permit. The second and unrelated violation alleged that the Partnership failed to immediately report a release of NGL from its Superior, Wisconsin terminal in mid-January 1999. The Partnership entered into a settlement agreement with the State of Wisconsin in June 2000, under which the Partnership agreed to pay $195,000 to resolve the matters. The Partnership subsequently recovered a substantial portion of the payment from third parties involved in the SEP II construction.

The Partnership continues to pursue a third party for costs incurred in connection with a release of crude oil in September 1998 and an NGL release in October 1998 near Plummer, Minnesota. There are no pending regulatory enforcement actions in connection with these releases. The Partnership

believes the outcome of this litigation will not materially affect the financial condition of the Partnership.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during 2000.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Partnership's Class A Common Units are listed and traded on the New York Stock Exchange, the principal market for the Class A Common Units, under the symbol LHP. The quarterly price range per Class A Common Unit and cash distributions paid per unit for 2000 and 1999 are summarized as follows:

	First	Second	Third	Fourth
2000 Quarters				
High	$40 7/8	$40 1/8	$42 3/4	$43.49
Low	$32	$33 1/4	$37 1/8	$36 5/8
Cash distributions paid	$0.875	$0.875	$0.875	$0.875

	First	Second	Third	Fourth
1999 Quarters				
High	$48 3/4	$46 15/16	$45 15/16	$43 13/16
Low	$41	$41 5/16	$42 1/2	$32 1/4
Cash distributions paid	$0.875	$0.875	$0.875	$0.875

On March 1, 2001, the last reported sales price of the Class A Common Units on the New York Stock Exchange was $44.62. At March 1, 2001, there were approximately 40,000 Class A Common Unitholders of which there were approximately 2,700 registered Class A Common Unitholders of record. There is no established public trading market for the Partnership's Class B Common Units, all of which are held by the General Partner.

Item 6. Selected Financial Data

The following table sets forth, for the periods and at the dates indicated, summary historical financial and operating data for the Partnership. The table is derived from the consolidated financial statements of the Partnership and notes thereto, and should be read in conjunction with those audited financial statements.

	Year ended December 31,				
	2000	1999	1998	1997	1996(1)
	(dollars in millions, except per unit amounts)				
Income Statement Data:					
Operating revenue	$ 305.6	$ 312.6	$ 287.7	$ 282.1	$ 274.5
Operating expenses(2)	189.1	182.3	182.3	174.0	187.1
Operating income	116.5	130.3	105.4	108.1	87.4
Interest and other income	4.8	3.4	6.0	9.7	9.6
Interest expense	(60.4)	(54.1)	(21.9)	(38.6)	(43.9)
Minority interest	(0.7)	(0.9)	(1.0)	(0.9)	(0.7)
Net income	$ 60.2	$ 78.7	$ 88.5	$ 78.3	$ 52.4
Net income per unit(3)	$ 1.78	$ 2.48	$ 3.07	$ 3.02	$ 2.11
Cash distributions paid per unit	$ 3.50	$ 3.485	$ 3.36	$ 2.92	$ 2.60
Financial Position Data (at year end):					
Property, plant and equipment, net	$ 1,281.9	$ 1,321.3	$ 1,296.2	$ 850.3	$ 763.5
Total assets	$ 1,376.7	$ 1,413.7	$ 1,414.4	$ 1,063.2	$ 975.9
Long-term debt	$ 799.3	$ 784.5	$ 814.5	$ 463.0	$ 463.0
Partners' capital					
Class A common unitholder	$ 488.6	$ 533.1	$ 453.4	$ 461.6	$ 376.3
Class B common unitholder	42.1	47.4	37.3	36.7	21.7
General Partner	5.2	5.6	4.3	3.5	1.6
	$ 535.9	$ 586.1	$ 495.0	$ 501.8	$ 399.6
Cash Flow Data:					
Cash flow from operating activities	$ 117.3	$ 101.6	$ 103.6	$ 106.6	$ 93.9
Cash flow used in investing activities	$ (20.7)	$ (91.1)	$ (427.9)	$ (101.7)	$ (84.7)
Cash flow from (used in) financing activities	$ (99.4)	$ (17.5)	$ 252.7	$ 24.1	$ 3.4

Capital expenditures included in investing activities	$ (21.7)	$ (82.9)	$ (487.3)	$ (126.9)	$ (76.7)
Operating Data:					
Barrel miles (billions)	341	350	391	389	384
Deliveries					
(thousands of barrels per day)					
United States	976	898	992	960	901
Ontario	362	471	570	552	550
	1,338	1,369	1,562	1,512	1,451

(1) 1996 results reflect the impact of the Settlement Agreement between the Partnership and customer representatives on all outstanding contested tariff rates.

(2) Operating expenses include provisions for prior years' rate refunds of $20.1 million in 1996.

(3) The General Partner's allocation of net income has been deducted before calculating net income per unit as follows: 2000 $8.8 million; 1999 $9.1 million; 1998 $8.0 million; 1997 $4.4 million; and 1996 $1.6 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The Lakehead System forms part of the world's longest liquid petroleum pipeline system that strategically links production from the Western Canadian Sedimentary Basin to key markets in the U.S. Midwest and eastern Canada. The NEB's *Canadian Energy Supply and Demand to 2025* report estimates the recoverable crude oil reserves in western Canada to be 9 billion barrels of conventional light crude and 5 billion barrels of conventional heavy crude. In addition to this, the estimate of bitumen located in the Alberta Oil Sands is 1.7 to 2.5 trillion barrels, with 300 billion barrels recoverable with current technology. This resource is similar in size to the proven reserves of Saudi Arabia. As U.S. domestic production declines over time, this western Canadian crude oil is an increasingly important source of supply to meet the rise in demand in the U.S. Midwest.

The year 2000 continued to be a time of recovery for western Canadian crude oil producers. Although world crude oil prices remained at high levels during the year, producers were cautious to invest in additional drilling activity. The low world crude oil prices of 1998 and early 1999 severely affected the financial positions of these companies; therefore 2000 was a time of rebuilding. Producers increased their drilling activity during the year, as OPEC implemented a mechanism to maintain world crude prices in the $22-$28/bbl range. Despite strong crude oil prices, there was competition for exploration and development dollars, as oil and gas companies tended to favor natural gas exploration over crude oil due to record natural gas prices during 2000.

Several other factors challenged the crude oil producing industry during 2000. At the beginning of the year, the winter drilling season was cut short due to warmer than normal weather in western Canada. Wet weather in the spring and summer delayed drilling activity and well tie-ins. Syncrude, a major oil sands producer, experienced longer than expected maintenance shut-downs, which adversely affected production. Lastly, mergers among some of the industry's most active explorers slowed drilling activity.

Despite these obstacles during 2000, the Partnership believes that production, and therefore deliveries on the System, will return to near-record levels in late 2002. In 2001, crude oil drilling activity is expected to surpass 2000 levels due to high commodity prices and ample cash flow in the oil and gas sector. Western Canadian producers remain committed to their heavy oil development projects, and long-term prospects for increased crude oil production remain positive. See —"Future Prospects".

Results of Operations

Net income for 2000 was $60.2 million ($1.78 per unit) compared with $78.7 million ($2.48 per unit) for 1999 and $88.5 million ($3.07 per unit) for 1998. Net income for 2000 was $18.5 million lower than 1999 primarily due to lower pipeline utilization and increased operating costs. The decline in utilization is a result of low crude oil prices in late 1998 and early 1999, which caused crude oil producers to limit their investment in oil producing facilities. Coupled with natural declines of crude oil reserves, reduced investment by oil producers has adversely affected short-term Partnership results due to lower volumes of crude oil being available for transport. The Partnership expects this situation to improve in 2001 and beyond. See—"Future Prospects".

Net income for 1999 was $9.8 million lower than 1998 primarily due to additional costs associated with expansions in that year and lower deliveries on the system. Net income per unit decreased $0.59 primarily due to the reduction in net income and an increase in the number of weighted-average units outstanding during 1999 compared with 1998. The Partnership issued 2.7 million Class A Common Units during April 1999, which increased the weighted-average number of Common Units outstanding from 26.2 million in 1998 to 28.0 million in 1999. At the end of 2000, the weighted average units outstanding was 28.9 million. See Note 1 to the Partnership's Consolidated Financial Statements.

Operating revenue for 2000 was $305.6 million, or $7.0 million less than 1999. The decrease was primarily due to the decline in deliveries. Deliveries averaged 1.338 million barrels per day in 2000, compared to 1.369 million barrels per day in 1999. The decline occurred because the supply of crude oil had not recovered to anticipated levels, further exacerbated by the effects of crude oil producer maintenance shutdowns and wetter than normal weather in western Canada, which delayed oil well tie-ins and other development activities. System utilization, measured in barrel miles, was 341 billion for 2000, compared to 350 billion for 1999, reflecting the decline in deliveries.

Operating revenue for 1999 was $312.6 million, or $24.9 million greater than 1998. The increase was primarily due to higher tariffs implemented for the SEP II and Terrace expansions. The increase in operating revenue from the impact of the tariffs was partially offset by the decrease in deliveries and by a tariff reduction of 1.83% on July 1, 1999, as required under the FERC's indexing methodology.

Crude oil and NGL deliveries averaged 1.369 million barrels per day in 1999, down from the record 1.562 million barrels in 1998. The decline in deliveries in 1999 was due to the impact of low world crude oil prices in 1998 and early 1999, which slowed exploration and development activities. System utilization, measured in barrel miles, decreased during 1999 primarily due to crude oil price related production declines.

Total operating expenses of $189.1 million in 2000 were higher than 1999 levels of $182.3 million as higher operating and administrative costs and higher depreciation expense associated with expansions of the Lakehead System were partially offset by lower power costs. Power costs decreased $5.6 million due to lower throughput volumes. Operating and administrative expense increased $9.1 million primarily due to higher oil measurement losses, higher property taxes associated with recent expansion projects and lower capitalized charges due to the decrease of construction activity in 2000. Oil measurement losses occur as part of normal operating conditions of a pipeline and can be classified as follows:

- Physical losses—occur through evaporation, shrinkage, difference in measurement between receipt and delivery locations and other incidents;
- Degradation losses—result from the downgrading of higher quality crude oils at their interface points in the pipeline with lower quality crude oils; and
- Revaluation losses—are a function of the price of crude oil and the level of over or short shipper balance inventories currently on hand.

Oil measurement losses were approximately $3.9 million higher in 2000 compared to 1999. This increase was primarily due to the higher differentials between the light and heavy crude oil prices, which increased the expense associated with inherent degradation between the batches of crude oil in the pipeline system. Depreciation expense increased $3.3 million primarily due to the full year impact of placing the Terrace Phase I project in service on April 1, 1999 and plant additions from the prior year.

Total operating expenses of $182.3 million in 1999 were at the same level as 1998. Power costs declined due to lower throughput volumes and operating efficiencies gained from the expanded pipeline facilities. Operating and administrative costs were relatively stable, as increased oil losses due to operational changes on the System were offset by lower maintenance activities during 1999. Depreciation charges relating to the expansions commenced effective with the tariff increases. This resulted in higher depreciation expense in 1999, which was partially mitigated by a FERC approved reduction of depreciation rates effective January 1, 1999.

Interest expense of $60.4 million in 2000 was $6.3 million higher than 1999 primarily due to lower capitalized interest resulting from less construction activity during 2000.

Interest expense of $54.1 million in 1999 increased $32.2 million from 1998 primarily due to additional debt financing arranged to fund a portion of the recent expansion projects. As well, capitalized interest was higher in 1998 due to the significant construction projects ongoing throughout the year. Interest is capitalized as part of the cost of constructing capital projects and interest capitalization generally ceases once a capital project is complete and ready for service.

Liquidity and Capital Resources

At December 31, 2000, cash and cash equivalents totaled $37.2 million, down $2.5 million from December 31, 1999. Of this $37.2 million, $27.9 million ($0.875 per unit) was used for the cash distribution paid on February 14, 2001, with the remaining $9.3 million available for capital expenditures and other business needs.

Cash flow from operating activities for 2000 was $117.3 million, compared to $101.6 million for 1999. The primary cause of this increase was the elimination of the rate refunds and related interest associated with the 1996 Settlement Agreement of $29.4 million. The rate refund obligation was fully repaid during 1999 and the 10% tariff credit was cancelled effective November 22, 1999. This increase is partially offset by a $18.5 million reduction in net income in the year 2000.

In 2000, the Partnership made capital expenditures of $21.7 million, of which $10.8 million was for pipeline system enhancements and $10.9 million for core maintenance activities. In 1999, the Partnership made capital expenditures of $82.9 million, of which $30.8 million was for SEP II, $33.2 million for Terrace, and $18.9 million for core maintenance and pipeline system enhancements.

In 2001, the Partnership anticipates spending approximately $9.0 million for routine pipeline system enhancements, $10.0 million for core maintenance activities, and $9.0 million for future phases of Terrace. Excluding major expansion projects, ongoing capital expenditures are expected to average approximately $20.0 million on an annual basis (approximately 50% for core maintenance and 50% for enhancement of the pipeline system). Core maintenance activities, such as the replacement of equipment and preventive maintenance programs, will be undertaken to enable the Partnership's pipeline system to continue to operate at its maximum operating capacity. Enhancements to the pipeline system, such as renewal and replacement of pipe, are expected to extend the life of the Lakehead System and permit the Partnership to respond to developing industry and government standards and the changing service expectations of its customers. See —"Lakehead System Growth".

On an annual basis, the Partnership makes expenditures of a capital and operating nature related to maintaining compliance of the Lakehead System with applicable environmental and safety regulations. Capital expenditures for safety and environmental purposes comprise a portion of the routine core maintenance and enhancement capital expenditures annually incurred by the Partnership. Amounts are not readily segregated since individual projects may be undertaken for a variety of reasons in addition to environment and safety considerations. Based on existing laws and regulations, future environmental and safety expenditures are not anticipated to have a material adverse impact on the Partnership's results of operations.

At December 31, 2000, the Partnership had outstanding $310.0 million aggregate principal amount of First Mortgage Notes bearing interest at the rate of 9.15% per annum, payable semi-annually. The notes are due and payable in ten equal annual installments beginning in the year 2002. The Partnership has a $350.0 million Revolving Credit Facility under which $190.0 million was outstanding at December 31, 2000. Interest rates on amounts drawn under this facility are variable and at the end of 2000 were approximately 6.2% on average.

In November 2000, pursuant to a $400.0 million shelf registration statement filed with the Securities and Exchange Commission ("SEC"), $100.0 million face amount of senior unsecured notes were issued to retire borrowings under the Revolving Credit Facility. The notes have an interest rate of

7.9% and mature in 2012. The Partnership previously sold $200.0 million of senior unsecured notes pursuant to the shelf registration in 1998. For additional details relating to the Partnership's debt, see Note 6 to the Partnership's Consolidated Financial Statements.

In April 1999, the Partnership issued an additional 2.7 million Class A Common Units, increasing the total number of Class A Common Units outstanding to 24,990,000. Net proceeds from the offering, including the General Partner's contribution, were $119.7 million. Proceeds were used to repay indebtedness under the Partnership's Revolving Credit Facility incurred to finance system expansions for SEP II and Terrace. Subsequent to this repayment, additional funds have been borrowed under the revolving credit facility to fund capital expenditures made during 1999. For additional information regarding the 1999 equity offering and Partnership organization, see Note 1 to the Partnership's Consolidated Financial Statements.

The Partnership distributes quarterly all of its Available Cash, which is generally defined to mean, with respect to any calendar quarter, the sum of all of the cash receipts of the Partnership plus net reductions to reserves less all of its cash disbursements and net additions to reserves. These reserves are retained to provide for the proper conduct of the Partnership's business, to stabilize distributions of cash to Unitholders and the General Partner and, as necessary, to comply with the terms of any agreement or obligation of the Partnership. On February 14, 2001, the Partnership paid a $0.875 per unit distribution with respect to the fourth quarter of 2000.

The Partnership anticipates that it will continue to have adequate liquidity to fund future recurring operating and investing activities. The Partnership intends to fund ongoing capital expenditures with the proceeds from future debt and equity offerings, other borrowings, cash generated from operating activities, and existing cash and cash equivalents. Cash distributions are expected to be funded with internally generated cash. The Partnership's ability to complete future debt and equity offerings will depend on prevailing market conditions and the then-existing financial condition of the Partnership.

Future Prospects

The outlook for future growth is expected to be positive for the Partnership. Growth is expected to come from two sources: growth of the Partnership's existing Lakehead System, and growth beyond the Lakehead System through new acquisitions.

Lakehead System Growth

Income and cash flows of the Partnership's existing pipeline business are sensitive to oil industry supply and demand in Canada and the United States and to the regulatory environment. As the Partnership's pipeline system is operationally integrated with the Enbridge Pipelines System in western Canada, the Partnership's revenues are dependent upon the utilization of the Enbridge Pipelines System by producers of western Canadian crude oil.

Although crude oil prices have been strong for the past year, exploration and production activity initially lagged, as producers of western Canadian crude oil were cautious to invest in new production. Total crude oil production in the western Canadian region declined by more than 200,000 barrels per day in 1999 from levels achieved in 1998, as a result of the curtailment of exploration and production activity.

During 2000, production increased modestly and the outlook is for continuing growth. As a leading indicator for crude oil production, oil well completions in 2000 more than doubled that from the prior year, as approximately 5,500 wells were completed in 2000 compared with approximately 2,700 wells in 1999. 2001 is expected to be a strong drilling year, with the number of oil well completions forecast to surpass 2000 levels. Although there has been a bias toward natural gas drilling, crude oil exploration is now on the rise and this trend is expected to continue through 2001. This resurgence is also supported by external forecasts for oil prices over the next several years. Forecasts for the West Texas Intermediate crude oil benchmark are in the low-to-mid-twenty dollars per barrel range. The

---

Partnership believes that these prices are sufficient to sustain continued growth in crude oil production from the Western Canadian Sedimentary Basin, particularly from the Alberta Oil Sands.

The Partnership believes that its intermediate-term outlook of increasing demand for transportation services on the System has been confirmed by CAPP's recent notification to proceed with Lakehead's Griffith Lateral project from Mokena, Illinois to Griffith, Indiana, and the Terrace Expansion Program Phase II in Canada. The Griffith Lateral project will allow for better access to the Chicago market and provide operational flexibility. The Terrace Phase II project is designed to add 40,000 barrels per day of additional heavy crude oil capacity to the Enbridge System in western Canada by the first half of 2002. Forecast production, for which the phase is designed, is expected to access U.S. Midwest refineries via the Lakehead System.

In the long-term, the Partnership is well positioned to benefit from increases in western Canadian crude oil supply through a combination of existing capacity and planned future expansion. Canada has substantial reserves of non-conventional hydrocarbon resources consisting predominantly of oil sands deposits in the province of Alberta. Firms involved in the production of heavy and synthetic crude oil from the oil sands region of western Canada have announced expansion projects for the next ten years with value in excess of Cdn. $30 billion and representing more than two million barrels per day of potential incremental production. The earliest of the projects, the Suncor Millennium Oil Sands Project, is expected to begin providing incremental production in late 2001. When completed, these projects are expected to provide substantial increases in the production of heavy and synthetic crude oil in western Canada well into the future.

Lakehead System Growth—Projects Recently Completed or Under Development

Terrace Expansion Program—The Partnership and Enbridge are undertaking a major capacity expansion project referred to as the Terrace expansion program. This expansion program consists of a multi-stage expansion of both the United States and Canadian portions of the System. The Terrace program is expected to ultimately provide an additional net 350,000 barrels per day of capacity to the System.

- Phase I of Terrace was completed in 1999 and included construction of new 36-inch diameter pipeline facilities from Kerrobert, Saskatchewan, to Clearbrook, Minnesota that added 170,000 barrels per day of capacity. The Partnership's portion of the cost of Phase I was approximately $140 million.

- The Partnership has announced that CAPP has provided notification requesting that the Partnership add facilities to enhance PADD 2 market access. The project was part of the future phases portion of Terrace. The cost of this portion of the project is approximately $35 million and, subject to final approvals, is expected to be in service in 2003.

- Enbridge has announced that Phase II of the program will proceed in 2001 with construction of facilities to increase capacity on the Canadian portion of the System. While Phase II does not involve construction on the Lakehead System, it is expected to benefit directly from the approximately 40,000 barrels per day increase in capacity of the Canadian portion of the System as additional volumes from the Alberta Oil Sands come on stream. Subject to timely approval by the NEB in Canada, it is expected that Phase II will be placed into service in 2002. The Partnership expects that near-record delivery levels on the Lakehead System will be achieved in late 2002, and that existing capacity will be highly utilized during 2002.

- Phase III of the Terrace expansion program is primarily designed to increase heavy oil transportation capacity on the Lakehead System between Clearbrook, Minnesota and Superior, Wisconsin by approximately 140,000 barrels per day. We expect this phase of the program to be

---

required in 2003. This phase and other future expansion projects on the System are subject to on-going discussions with producers.

- A tariff surcharge for Terrace, of approximately $0.013 per barrel (for light crude oil from the Canadian border to Chicago), went into effect on April 1, 1999. On April 1, 2001, the surcharge was increased by $0.013 to $0.026 per barrel in an effort to rebalance the project economics between the Partnership and Enbridge. See "Items 1 & 2. Business and Properties, —Tariffs, —Tariff Agreement." The tariff surcharge assumes that all three phases of the Terrace project will be completed. If CAPP does not provide notice on or before July 1, 2001, to proceed with the final phase, the tariff agreement approved by the FERC, provides that the Partnership will be allowed to adjust the tariff surcharge on a cost of service basis, to allow recovery of, and a return on, the Terrace investment. This includes any revenue variances between the application of the toll increment and the actual annual Terrace cost of service. Management expects that CAPP will likely provide notice for Phase III on or before the notice date, or alternatively, will seek an extension of the date.

Growth Beyond the Lakehead System

Diversification of the Partnership's energy transportation business is a key objective of its strategic plan. Business development efforts to grow through the development of complementary businesses and through acquisitions are a focus of the strategic plan. The initial emphasis will be on crude oil, refined products and natural gas pipelines and terminals that fit the Partnership's investment profile of accretive cash flows and low investment risk. The Partnership expects such assets to become available with the continuing rationalization of the energy infrastructure in the U.S., as existing owners focus on other core aspects of their businesses. The Partnership is well positioned to participate in these opportunities, as it is an established operator with a strong track record of reliability and is a low cost source of capital for mature assets with stable cash flows.

The Partnership intends to expand beyond the markets it currently serves in PADD 2 by seeking out new opportunities throughout the U.S. A market of particular interest is the U.S. Gulf Coast area. External forecasts indicate that crude oil production in the Gulf of Mexico will increase by about one million barrels per day over the next 5 years and will require additional infrastructure to transport the crude oil to shore. The Partnership will actively pursue these opportunities to provide terminal and logistics solutions to the major crude oil producers in this region.

The Partnership also expects to have the opportunity to acquire a number of oil and gas pipeline assets of its affiliate, Enbridge, as these systems achieve risk and return profiles attractive to the Partnership. On March 8, 2001 a definitive agreement to acquire the assets of Enbridge Pipelines (North Dakota) from Enbridge was announced. The assets consist of a 950-mile crude oil pipeline system with capacity of 84,000 barrels per day, which transports crude oil from Montana, North Dakota and western Canadian oil fields to the Lakehead System and a connecting carrier at Clearbrook, Minnesota. The purchase price for this transaction is approximately $33.0 million, and the closing is expected to occur around May 1, 2001. The terms of this acquisition were negotiated and approved by a special committee of independent directors.

Regulatory Issues

The Partnership is subject to a rate regulatory methodology that prescribes rate ceilings that are adjusted each July 1. The rate ceilings are adjusted by reference to annual changes in the Producer Price Index for Finished Goods minus 1 percent ("PPIFG-1"). The General Partner expects the PPIFG-1 to increase approximately 2.7% for 2001. This increase in the PPIFG-1 should not have a material effect on 2001 operating revenue since the increase does not apply to SEP II or Terrace and will be effective mid-year 2001. The FERC has recently completed a five-year review of the

appropriateness of the indexing methodology and specifically the PPIFG-1 index. It decided to continue the use of the PPIFG-1 index to adjust pipeline rates for a subsequent five-year period. At the end of this period, in July 2005, the FERC intends to again review the index to determine whether it continues to measure adequately the cost changes in the oil pipeline industry.

The 1996 Settlement Agreement between the Partnership, CAPP and ADOE provided that the agreed underlying tariff rates would be subject to indexing as prescribed by FERC regulation and that CAPP and ADOE would not challenge any rates within the indexed ceiling for a period of five years, expiring October 2001. To challenge the rates, a shipper must show that the amount of any indexed rate increase is so substantially in excess of the pipeline's increase in costs as to be unjust and unreasonable. The Partnership believes that changes in costs have been in line with changes in the index, and does not expect a challenge. The Partnership strives to have a strong working relationship with its shippers, and therefore rate challenges are not currently anticipated.

The indexed rate environment, the Settlement Agreement, and other negotiated settlements with customers for SEP II and Terrace are benefiting the Partnership and its customers by restoring stability and providing predictable tariff rates. To the extent allowed under FERC orders or by agreement with customers, the Partnership has filed, and will continue to file, for additional tariff increases from time to time to reflect ongoing expansion programs.

New Safety Legislation

During 2001, various legislation changes to the Pipeline Safety Act come into effect, including those that affect pipeline operator qualifications and integrity plans for pipelines in high consequence areas. The Partnership does not expect the legislation changes to have a material adverse impact on its results of operations, as the Partnership believes its established safety and integrity programs already meet or exceed the new standards. See "Items 1. & 2. Business and Properties, —Environmental and Safety Regulation, —Safety Regulation."

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

To the extent that a portion of its indebtedness carries a floating rate, the Partnership's earnings are exposed to movements in interest rates. This exposure is managed through long-term debt to equity ratio targets, appropriate allocation of fixed and floating rate debt and the use of interest rate risk management agreements. The Partnership's cash flows are not significantly impacted by changes in commodity prices, as the Partnership does not own the crude oil and NGL it transports. However, commodity prices have a significant impact on the underlying supply of and demand for crude oil and NGL that the Partnership transports. The Partnership has minimal foreign exchange risk, and has entered into forward contracts to hedge its exposure to movements of future exchange rates. For additional details relating to the Partnership's foreign exchange hedging, see Note 11 to the Partnership's Consolidated Financial Statements. The Partnership does not currently hold or issue derivative instruments for trading purposes.

The following table provides information about the Partnership's derivative financial instruments and other financial instruments that are sensitive to changes in interest rates, including interest rate swaps and debt obligations. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the table presents

notional amounts and weighted average interest rates by expected (contractual) maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract.

	Expected Maturity Date							
December 31, 2000	**2001**	**2002**	**2003**	**2004**	**2005**	**There-After**	**Total**	**Fair Value**
					($U.S. in millions)			
Liabilities								
Fixed Rate:								
First Mortgage Notes	$ 0	$ 31.0	$ 31.0	$ 31.0	$ 31.0	$ 186.0	$ 310.0	$ 346.5
Interest Rate	—	9.15%	9.15%	9.15%	9.15%	9.15%	—	—
Senior Unsecured Notes	$ 0	$ 0	$ 0	$ 0	$ 0	$ 300.0	$ 300.0	$ 290.3
Interest Rate	—	—	—	—	—	7.34%	—	—
Variable Rate:								
Revolving Credit Facility	$ 0	$ 0	$ 0	$ 0	$ 190.0	$ 0	$ 190.0	$ 190.0
Weighted Average Interest Rate	—	—	—	—	6.2%	—	—	—
Interest Rate Derivatives								
Interest Rate Swaps:								
Variable to Fixed	$ 0	$ 50.0	$ 0	$ 0	$ 0	$ 0	$ 50.0	$ (0.1)
Average Pay Rate	—	6.23%	—	—	—	—	—	—

The fair value of the First Mortgage Notes and Senior Unsecured Notes at December 31, 2000, was $346.5 million (1999—$334.1 million) and $290.3 million (1999—$177.2 million), respectively. The Partnership had $190.0 million (1999—$275.0 million) of variable rate debt outstanding under the Revolving Credit Facility at December 31, 2000, with a fair value of $190.0 million (1999—$275.0 million), at an average interest rate of 6.2% (1999—5.9%). It is the Partnership's intention to roll over short-term debt under the Revolving Credit Facility as the debt matures. The Revolving Credit Facility matures during September 2005. The maturity date may be extended by one year, on the anniversary date of the facility, subject to the approval of the lending banks. The fair value of the interest rate swap agreements at December 31, 2000 was ($0.1) million (1999—$0.7 million). For additional information concerning the Partnership's debt obligations, please see Note 6 to the Partnership's Consolidated Financial Statements.

Item 8. Financial Statements and Supplementary Data

The consolidated financial statements of the Partnership together with the notes thereto and the independent accountants' report thereon, appear on pages F-2 through F-12 of this Report, and are incorporated by reference. Reference should be made to the Index to Financial Statements, Supplementary Information and Financial Statement Schedules on page F-1 of this Report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

(a) Directors and Executive Officers of the Registrant

The Registrant is a limited partnership and has no officers, directors or employees. Set forth below is certain information concerning the directors and executive officers of the General Partner. Enbridge Pipelines, the sole stockholder of the General Partner, elects the directors of the General Partner on an annual basis. All officers of the General Partner serve at the discretion of the directors of the General Partner.

Name	Age	Position with General Partner

J.R. Bird	52	President and Director
P.D. Daniel	54	Director
L.H. DeBriyn	54	Vice President and Director
E.C. Hambrook	63	Director
G.K. Petty	59	Director
C.A. Russell	67	Director
D.P. Truswell	57	Director
J.K. Whelen	41	Treasurer
J.L. Balko	35	Chief Accountant
S.M. Curwin	40	Corporate Secretary

Mr. Bird was elected President and Director of the General Partner in September 2000. Mr. Bird previously served as Treasurer of the General Partner from October 1996 through October 1997. He has also served as Group Vice President, Transportation of Enbridge and President of Enbridge Pipelines since September 2000. Prior thereto, he served as Senior Vice President, Corporate Planning and Development of Enbridge from August 1997 through August 2000 and as Vice President and Treasurer of Enbridge from January 1995 to August 1997.

Mr. Daniel was elected a Director of the General Partner in July 1996 and served as its President from July 1996 through October 1997. Mr. Daniel has served as President of Enbridge since September 2000 and as Chief Executive Officer of Enbridge since January 2001. Prior thereto, Mr. Daniel also served as President and Chief Operating Officer—Energy Delivery of Enbridge from June 1998 to December 2000. Prior thereto, Mr. Daniel served as Executive Vice President and Chief Operating Officer—Energy Transportation Services of Enbridge from September 1997 through June 1998, as Senior Vice President of Enbridge from May 1994 to August 1997, as President and Chief Executive Officer of Enbridge Pipelines from August 1996 to August 1997, and as President and Chief Operating Officer of Enbridge Pipelines from May 1994 to August 1996.

Mr. DeBriyn was elected Vice President and Director of the General Partner in July 1999. Prior thereto, he served as Vice President, Canadian Operations, of Enbridge Pipelines from July 1996 to July 1999, and prior thereto, in managerial positions in operations with Enbridge Pipelines and the General Partner.

Mr. Hambrook was elected Director of the General Partner in January 1992 and served as Chairman of the General Partner from July 1996 until July 1999. He also serves on the Audit, Finance & Risk Committee. Mr. Hambrook is the President of Hambrook Resources Inc.

Mr. Petty was elected Director of the General Partner on February 22, 2001 and serves on the Audit, Finance & Risk Committee. Mr. Petty has served as Director of Enbridge Inc. since January 2001 and as Director of CAE Incorporated since August 1996. Mr. Petty served as President and Chief Executive Officer of Telus Corporation from November 1994 to November 1999.

Mr. Russell was elected Director of the General Partner in October 1985 and serves as the Chairman of the Audit, Finance & Risk Committee. Mr. Russell served as Chairman and Chief Executive Officer of Norwest Bank Minnesota North, N.A., from January through December 1995. He also served as a Director of Minnesota Power and Light Co. until May 1996.

Mr. Truswell was elected Director of the General Partner in 1991. Since September 2000, Mr. Truswell has served as Group Vice President and Chief Financial Officer of Enbridge and from May 1994 through August 2000 served as Senior Vice President and Chief Financial Officer of Enbridge.

Mr. Whelen was elected Treasurer of the General Partner in January 2000. He has served as Assistant Treasurer of Enbridge since November 1997. Prior thereto, he served as Manager, Corporate Finance, of Enbridge from December 1995 to October 1997, and prior thereto, as Manager, Corporate Finance, of The Consumers' Gas Company Ltd.

Ms. Balko has served as Chief Accountant since October 1999. Prior thereto, she served in managerial positions in accounting with Enbridge Pipelines since January 1998, and was with The Westaim Corporation from November 1995 to December 1998.

Mr. Curwin has served as Corporate Secretary of the General Partner since October 2000. He served as Assistant Secretary of the General Partner since October 1999. Prior thereto, he held various positions in the private practice of law in Minneapolis, Minnesota from October 1994 to October 1999.

Item 11. Executive Compensation

The General Partner is responsible for the management and operation of the Partnership. The Partnership does not directly employ any of the persons responsible for managing or operating the Partnership's operations, but instead reimburses the General Partner or its affiliates for the services of such persons. The General Partner, in turn, because it has no employees, has entered into services agreements with Enbridge (U.S.) and other affiliates to provide the services required by the Partnership.

Item 12. Security Ownership of Certain Beneficial Owners and Management

(a)

Security Ownership of Certain Beneficial Owners

Title of Class	*Name and Address of Beneficial Owner*	*Amount and Nature of Beneficial Ownership*	*Percent of Class*
Class A Common Units	No person or group is known to be the beneficial owner of more than 5% of the Class A Common Units as at March 1, 2001		
Class B Common Units	Lakehead Pipe Line Company, Inc. Lake Superior Place 21 West Superior Street Duluth, Minnesota 55802-2067	3,912,750	100

(b)

Security Ownership of Management

Class A Common Units beneficially held by all directors and officers as a group represented less than 1% of the Partnership's outstanding Class A Common Units.

Item 13. Certain Relationships and Related Transactions

The Partnership is managed by the General Partner pursuant to the Amended and Restated Agreements of Limited Partnership of the Partnership and the Operating Partnership, as amended ("Partnership Agreements"). The General Partner has entered into a service agreement with Enbridge U.S. whereby the General Partner will utilize the resources of Enbridge U.S. to operate the Partnership. Under this agreement, Enbridge U.S. will be reimbursed at cost for all direct and indirect expenses it incurs or payments it makes on behalf of the Partnership. The General Partner also receives certain administrative, engineering, treasury and computer services from Enbridge and Enbridge Pipelines for the benefit of the Partnership. The Partnership reimburses the General Partner for the cost of these services. For information about reimbursements to the General Partner, see Note 7 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an Agency Agreement with Tidal Energy Marketing Inc., a joint venture owned 50% by Enbridge, for a term of five years. For a fee and a share of the lease payments in excess of a specified base lease rate, Tidal has agreed to serve as leasing agent for the Partnership's crude oil storage tanks at its Hartsdale facility in Schererville, Indiana. See Note 7 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an easement acquisition agreement with Enbridge Holdings (Mustang) Inc. ("Enbridge Mustang"), a subsidiary of Enbridge U.S. Pursuant to this agreement, using funds advanced by the Partnership, Enbridge Mustang acquired properties for the purpose of granting a pipeline easement to the Partnership to allow construction of SEP II's new Line 14. Enbridge Mustang is in the process of reselling these properties. As each parcel is resold, Enbridge Mustang retains an easement for transfer to the Partnership and repays the Partnership for the funds advanced to make the original purchase of the property (less the cost of the easement). Enbridge Mustang is being reimbursed for all costs associated with this process at cost by the Partnership and will be indemnified by the Partnership from and against all liabilities that may arise in connection with this process. See Note 7 to the Partnership's Consolidated Financial Statements.

The Partnership has entered into an agreement with Mustang Pipe Line Partners ("Mustang") and Mobil Pipe Line Company ("Mobil") to provide for a joint tariff covering shipments of western Canadian crude oil to the Patoka pipeline hub south of Chicago. Mustang is a Delaware general partnership owned by Mobil Illinois Pipe Line Company and Enbridge Mustang. Shipments covered by the joint tariff travel on the Lakehead System to Chicago and to the Patoka pipeline hub through the Mustang pipeline system. The Partnership has also entered into an agreement with Mustang, Mobil, and Equilon Pipeline Company L.L.C. ("Equilon") to provide for a joint tariff covering shipments of western Canadian crude oil to the Wood River refining center west of Patoka through the Partnership's, Mustang's, and Equilon's pipelines. The joint tariff agreements provide for lower transportation costs to shippers desiring access to the Patoka/Wood River market area, an incentive which the Partnership believes complements its expansion programs.

Under the terms of the Revolving Credit Facility Agreement, the Partnership and the General Partner may draw down funds up to a combined maximum of $350.0 million. For additional details, see Note 6 to the Partnership's Consolidated Financial Statements.

The Partnership has an arrangement with the General Partner, under which the General Partner may, at its discretion, provide loans to the Partnership in an amount not to exceed $200.0 million. This uncommitted facility provides an alternative source of funds at market interest rates in the event that a disruption in the capital markets delayed access to debt and equity markets. In March 1999, the Partnership borrowed, and subsequently repaid in early April, $25.0 million under this arrangement.

For discussion of distribution restrictions and incentive distributions payable to the General Partner, see Note 3 to the Partnership's Consolidated Financial Statements.

The Partnership also expects to have the opportunity to acquire a number of oil and gas pipeline assets of its affiliate, Enbridge, as these systems achieve risk and return profiles attractive to the Partnership. On March 8, 2001 a definitive agreement to acquire the assets of Enbridge Pipelines (North Dakota) from Enbridge was announced. The assets consist of a 950-mile crude oil pipeline system with capacity of 84,000 barrels per day, which transports crude oil from Montana, North Dakota and western Canadian oil fields to the Lakehead System and a connecting carrier at Clearbrook, Minnesota. The purchase price for this transaction is approximately $33.0 million, and the closing is expected to occur around May 1, 2001. The terms of this acquisition were negotiated and approved by a special committee of independent directors.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) As to financial statements, supplementary information and financial statement schedules, reference is made to "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

(b) The registrant filed the following reports on Form 8-K during the fourth quarter of 2000: A report on Form 8-K was filed on November 15, 2000 indicating the Partnership's Independent Accountant's consent to the incorporation by reference in the Partnership's Registration Statement on Form S-3, dated November 15, 2000, of the Accountant's January 7, 2000 report relating to the financial statements of the Partnership.

A report on Form 8-K was filed on November 20, 2000 indicating the Partnership entered into an Underwriting Agreement, dated November 16, 2000, in connection with the Partnership's public offering of $100,000,000 aggregate principal amount of 7.9% Senior Notes due 2012.

(c) The following Exhibits (numbered in accordance with Item 601 of Regulation S-K) are filed or incorporated herein by reference as part of this Report.

Exhibit Number	Description
3.1	Certificate of Limited Partnership of the Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 3.1)
4.1	Form of Certificate representing Class A Common Units. (Registrant's Form 8-A/A, dated May 2, 1997)
4.2	Amended and Restated Agreement of Limited Partnership of the Partnership, dated April 15, 1997. (Registrant's Form 8-A/A, dated May 2, 1997)
10.1	Note Agreement and Mortgage, dated December 12, 1991. (1991 Form 10-K—Exhibit 10.1)
10.2	[Intentionally Omitted].
10.3	Distribution Support Agreement, dated December 27, 1991, among the Partnership, Lakehead Pipe Line Company, Inc. and Interprovincial Pipe Line Inc. (1991 Form 10-K—Exhibit 10.3)
10.4	Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (1992 Form 10-K—Exhibit 10.4)
10.5	Amended Services Agreement, dated February 29, 1988, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1991 Form 10-K—Exhibit 10.4)
10.6	Amended Services Agreement, dated January 1, 1992, between Interprovincial Pipe Line Inc. and Lakehead Pipe Line Company, Inc. (1992 Form 10-K—Exhibit 10.6)

10.7	Certificate of Limited Partnership of the Operating Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 10.1)
10.8	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated December 27, 1991. (1991 Form 10-K—Exhibit 10.6)
10.9	Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's Registration Statement No. 33-43425—Exhibit 10.4)
10.10	Amendment No. 1 to the Certificate of Limited Partnership of Lakehead Services, Limited Partnership. (Partnership's

Registration Statement No. 33-43425—Exhibit 10.16)

10.11	Amended and Restated Agreement of Limited Partnership of Lakehead Services, Limited Partnership, dated December 27, 1991. (1991 Form 10-K—Exhibit 10.9)
10.12	Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (1991 Form 10-K—Exhibit 10.10)
10.13	LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (1991 Form 10-K—Exhibit 10.11)
10.14	Services Agreement, dated January 1, 1996, between IPL Energy (U.S.A.) Inc. and Lakehead Pipe Line Company, Inc. (1995 Form 10-K—Exhibit 10.14)
10.15	Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal and Harris Trust and Savings Bank. (1996 Form 10-K —Exhibit 10.15)
10.16	First Amendment to Amended and Restated Revolving Credit Agreement, dated September 6, 1996, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services, Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and the Bank of Montreal. (1996 Form 10-K—Exhibit 10.16)
10.17	Second Amendment to Amended and Restated Revolving Credit Agreement, dated June 16, 1998, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P., Lakehead Services Limited Partnership, Lakehead Pipe Line Company, Limited Partnership and Bank of Montreal, The Toronto Dominion Bank, Canadian Imperial Bank of Commerce, ABN AMRO Bank, N.V. Cayman Islands Branch and Bank of Montreal, as agent. (Form 10-Q/A, filed September 14, 1998—Exhibit 10.1)
10.18	Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy. (1996 Form 10-K—Exhibit 10.17)
10.19	Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender.
10.20	Treasury Services Agreement, dated January 1, 1996, between IPL Energy Inc. and Lakehead Pipe Line Company, Inc. (1996 Form 10-K—Exhibit 10.18)
10.21	Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project.

10.22	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.1, dated October 20, 1998)
10.23	First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.2, dated October 20, 1998)
10.24	Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.3, dated October 20, 1998)
10.25	Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank. (1998 Form 8-K of Lakehead Pipe Line Company, Limited Partnership—Exhibit 4.4, dated October 20, 1998)
10.26	Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender.
10.27	Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and

the Chase Manhattan Bank. (2000 Form 8-K of Lakehead Pipe Line Company, Limited Partnership-Exhibit 4.2, dated November 16, 2000).

21	Subsidiaries of the Registrant.
23.1	Consent of PricewaterhouseCoopers LLP
27	Financial Data Schedule as of and for the year ended December 31, 2000.

All Exhibits listed above, with the exception of Exhibits 10.19, 10.21, 10.26, 21, 23.1 and 27 are incorporated herein by reference to the documents identified in parentheses.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Lakehead Pipe Line Company, Inc., Lake Superior Place, 21 West Superior Street, Duluth, Minnesota 55802-2067.

(d) As to financial statement schedules, reference is made to "Financial Statement Schedules" on page F-1 of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

LAKEHEAD PIPE LINE PARTNERS, L.P.
(Registrant)

By: Lakehead Pipe Line Company, Inc.,
as General Partner

Date: March 20, 2001

By: /s/ J.R. BIRD

J.R. Bird
(President)

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on March 20, 2001 by the following persons on behalf of the Registrant and in the capacities indicated with Lakehead Pipe Line Company, Inc., General Partner.

/s/ J.R. BIRD	/s/ E.C. HAMBROOK
J.R. Bird President and Director (Principal Executive Officer)	E.C. Hambrook Director
/s/ L.H. DEBRIYN	/s/ J.L. BALKO
L.H. DeBriyn Vice President and Director	J.L. Balko Chief Accountant (Principal Financial and Accounting Officer)
/s/ C.A. RUSSELL	/s/ P.D. DANIEL
C.A. Russell Director	P.D. Daniel Director
/s/ G.K. PETTY	/s/ D.P. TRUSWELL
G.K. Petty Director	D.P. Truswell Director

INDEX TO FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND FINANCIAL STATEMENT SCHEDULES

LAKEHEAD PIPE LINE PARTNERS, L.P.

FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this Report have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Partners of
Lakehead Pipe Line Partners, L.P.

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of partners' capital and of cash flows present fairly, in all material respects, the financial position of Lakehead Pipe Line Partners, L.P. and its subsidiary (the "Partnership") at December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
January 12, 2001

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF INCOME

	Year ended December 31,		
	2000	1999	1998
	(dollars in millions, except per unit amounts)		
Operating Revenue	$ 305.6	$ 312.6	$ 287.7
Expenses			
Power	47.4	53.0	69.0
Operating and administrative	80.6	71.5	71.9
Depreciation	61.1	57.8	41.4
	189.1	182.3	182.3

Operating Income	116.5	130.3	105.4
Interest and Other Income	4.8	3.4	6.0
Interest Expense (Note 6)	(60.4)	(54.1)	(21.9)
Minority Interest	(0.7)	(0.9)	(1.0)
Net Income	$ 60.2	$ 78.7	$ 88.5
Net Income Per Unit (Note 4)	$ 1.78	$ 2.48	$ 3.07
Weighted Average Units Outstanding (millions)	28.9	28.0	26.2

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

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year ended December 31,		
	2000	1999	1998
	(dollars in millions)		
Cash Provided from Operating Activities			
Net income	$ 60.2	$ 78.7	$ 88.5
Adjustments to reconcile net income to cash provided from operating activities:			
Depreciation	61.1	57.8	41.4
Interest on accrued rate refunds (Note 9)	—	0.7	2.1
Minority interest	0.7	0.9	1.0
Other	0.8	0.9	0.1
Changes in operating assets and liabilities:			
Accounts receivable and other	1.1	(3.2)	(3.3)
Oil inventory	(4.2)	(3.1)	0.5
Materials and supplies	(0.3)	(0.3)	—
General Partner and affiliates	(3.2)	(1.2)	(1.0)
Accounts payable and other	(0.2)	(2.4)	2.1
Interest payable	0.2	0.8	0.2
Property and other taxes	1.1	1.4	0.5
Payment of rate refunds and related interest (Note 9)	—	(29.4)	(28.5)
	117.3	101.6	103.6
Investing Activities			
Short-term investments, net	—	—	53.9
Repayments from (advances to) affiliate (Note 7)	1.6	24.5	(25.5)
Additions to property, plant and equipment	(21.7)	(82.9)	(487.3)
Changes in construction payables	(0.6)	(32.7)	31.0
	(20.7)	(91.1)	(427.9)
Financing Activities			
Proceeds from unit issuance, net (Note 1)	—	119.7	—
Distributions to partners (Note 3)	(110.4)	(107.3)	(95.3)
Variable rate financing, net (Note 6)	(85.0)	(30.0)	152.0
Fixed rate financing, net (Note 6)	96.9	—	196.9
Minority interest	(1.1)	0.1	(0.9)
Other	0.2	—	—

	(99.4)	(17.5)	252.7
Decrease in Cash and Cash Equivalents	(2.8)	(7.0)	(71.6)
Cash and Cash Equivalents at Beginning of Year	40.0	47.0	118.6
Cash and Cash Equivalents at End of Year	$ 37.2	$ 40.0	$ 47.0

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

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

	December 31,	
	2000	1999
	(dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 37.2	$ 40.0
Due from General Partner and affiliates	1.5	—
Accounts receivable and other	25.7	26.8
Oil inventory	8.9	4.7
Advances to affiliate (Note 7)	5.9	7.5
Materials and supplies	7.7	7.4
	86.9	86.4
Deferred charges and other	7.9	6.0
Property, plant and equipment, net (Note 5)	1,281.9	1,321.3
	$ 1,376.7	$ 1,413.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ —	$ 1.7
Accounts payable and other	17.4	18.2
Interest payable	6.5	6.3
Property and other taxes	14.4	13.3
	38.3	39.5
Long-term debt (Note 6)	799.3	784.5
Minority interest	3.2	3.6
Contingencies (Note 10)		
	840.8	827.6
Partners' capital		
Class A common unitholders (Units authorized and issued—24,990,000)	488.6	533.1
Class B common unitholder (Units authorized and issued—3,912,750)	42.1	47.4
General Partner	5.2	5.6
	535.9	586.1
	$ 1,376.7	$ 1,413.7

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

LAKEHEAD PIPE LINE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

	Class A Common Unitholders	Class B Common Unitholder	General Partner	Total
	(dollars in millions)			
Partners' capital at December 31, 1997	$ 461.6	$ 36.7	$ 3.5	$ 501.8
Net income allocation	66.7	13.8	8.0	88.5
Distributions to partners	(74.9)	(13.2)	(7.2)	(95.3)
Partners' capital at December 31, 1998	453.4	37.3	4.3	495.0
Allocation of proceeds from Unit issuance (Note 1)	106.2	12.4	1.1	119.7
Net income allocation	58.3	11.3	9.1	78.7
Distributions to partners	(84.8)	(13.6)	(8.9)	(107.3)
Partners' capital at December 31, 1999	533.1	47.4	5.6	586.1
Net income allocation	43.0	8.4	8.8	60.2
Distributions to partners	(87.5)	(13.7)	(9.2)	(110.4)
Partners' capital at December 31, 2000	$ 488.6	$ 42.1	$ 5.2	$ 535.9

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

LAKEHEAD PIPE LINE PARTNERS, L.P.

NOTES TO THE 2000 CONSOLIDATED FINANCIAL STATEMENTS

(dollars in millions, except per unit amounts)

1. Partnership Organization and Nature of Operations

Lakehead Pipe Line Partners, L.P. ("Lakehead Partnership") is a publicly traded limited partnership that owns a 99% limited partner interest in Lakehead Pipe Line Company, Limited Partnership ("Operating Partnership"), both Delaware limited partnerships, and collectively known as the "Partnership". The Partnership was formed in 1991 to acquire, own and operate the crude oil and natural gas liquids pipeline business of Lakehead Pipe Line Company, Inc. (the sole "General Partner"). The General Partner is a wholly-owned subsidiary of Enbridge Pipelines Inc. ("Enbridge Pipelines"), a Canadian company owned by Enbridge Inc. of Calgary, Alberta, Canada.

On April 28, 1999, the Lakehead Partnership issued an additional 2,700,000 Class A Common Units for total net proceeds of $119.7 million, including the General Partner's contribution, bringing the total number of Class A Common Units issued to 24,990,000. Class A Common Units are publicly traded and represent an 84.7% limited partner interest in the Partnership. The General Partner has a 13.4% limited partner (in the form of 3,912,750 Class B Common Units) and 1.0% general partner interest in the Lakehead Partnership, as well as a 1.0% general partner interest in the Operating Partnership (an effective 15.3% combined interest in the Partnership).

The Lakehead Partnership held a 1% general partner interest in Lakehead Services, Limited Partnership ("Services Partnership"), a Delaware limited partnership, originally formed to facilitate the financing of the Operating Partnership. During November 2000 the Services Partnership was dissolved.

The Operating Partnership is engaged in the transportation of crude oil and natural gas liquids through a common carrier pipeline system. Substantially all of the shipments delivered originate in western Canadian oil fields. The majority of the shipments reach the Operating Partnership at the Canada/United States border in North Dakota, through a Canadian pipeline system owned by Enbridge Pipelines. Deliveries are made in the Great Lakes region of the United States and to the Province of Ontario, principally to refineries, either directly or through the connecting pipelines of other companies.

2. Summary of Significant Accounting Policies

The consolidated financial statements of the Partnership are prepared in accordance with generally accepted accounting principles. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures. Actual results could differ from those estimates and assumptions; however, management believes that such differences would not be material.

Principles of Consolidation

The financial statements of the Partnership include the accounts of the Lakehead Partnership and the Operating Partnership on a consolidated basis. The equity method was used to account for the Partnership's 1.0% general partner interest in the Services Partnership prior to dissolution. The General Partner's 1.0% interest in the Operating Partnership is accounted for by the Partnership as a minority interest.

Regulation of Pipeline System

As an interstate common carrier oil pipeline, rates and accounting practices are under the regulatory authority of the Federal Energy Regulatory Commission ("FERC").

Revenue Recognition

Substantially all pipeline system revenues are derived from transportation of crude oil and natural gas liquids ("NGL") and are recognized in income upon delivery.

Cash and Cash Equivalents

Cash equivalents are defined as all highly marketable securities with a maturity of three months or less when purchased. They are accounted for as held-to-maturity securities and valued at amortized cost.

Oil Inventory

Oil inventory is stated at current market prices.

Materials and Supplies

Materials and supplies are stated at the lower of cost or market value.

Deferred Financing Charges

Deferred financing charges are amortized on the straight-line basis over the life of the related debt, which is comparable to results using the effective interest method.

Property, Plant and Equipment

Property, plant and equipment is stated at cost. Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. An allowance for interest incurred on external borrowings during construction is capitalized. Depreciation of property, plant and equipment is provided on the straight-line basis over their estimated service lives. When property, plant and equipment are retired or otherwise disposed of, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss is recognized.

Income Taxes

The Partnership is not a taxable entity for federal and state income tax purposes. Accordingly, no recognition has been given to income taxes for financial reporting purposes. The tax on Partnership net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the Partnership Agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined due to inaccessible information regarding each partner's tax attributes in the Partnership.

Off Balance Sheet Financial Instruments

Gains and losses realized on financial instruments used to hedge the Partnership's exposure to movements of future interest rates are recognized currently with the related interest expense.

The Partnership uses the services of the General Partner and its affiliates for managing and operating its pipeline business. Under the terms of service agreements, services provided from the General Partner's Canadian affiliates are reimbursed at cost in Canadian currency. In order to hedge these transactions for 2001, the Partnership has entered into an average rate forward contract that settles at the end of each month during the year to coincide with the related service payments. The gains and losses on these financial instruments are deferred and will be recognized concurrently with the monthly service agreement payments and included in operating and administrative expenses.

Comparative Amounts

Comparative amounts are reclassified to conform with the current year's financial statement presentation.

3. Cash Distributions

The Partnership distributes quarterly all of its "Available Cash", which is generally defined in the Partnership Agreement as cash receipts less cash disbursements and net additions to reserves for future requirements. These reserves are retained to provide for the proper conduct of the Partnership business and as necessary to comply with the terms of any agreement or obligation of the Partnership. Distributions by the Partnership of its Available Cash generally are made 98.0% to the Class A and B Common Unitholders and 2.0% to the General Partner, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the Unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0%, 25.0% and 50.0% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B Common Units, respectively.

In 2000, the Partnership paid cash distributions of $3.50 per unit, consisting of $0.875 per unit paid in February, May, August and November. In 1999, the Partnership paid cash distributions of $3.485 per unit, consisting of $0.86 per unit paid in February and $0.875 per unit paid in May, August and November. In 1998, the Partnership paid cash distributions of $3.36 per unit, consisting of $0.78 per unit paid in February and $0.86 per unit paid in May, August and November.

4. Net Income Per Unit

Net income per unit is computed by dividing net income, after deduction of the General Partner's allocation, by the weighted average number of Class A and Class B Common Units outstanding. The General Partner's allocation is equal to an amount based upon its 1.0% general partner interest, adjusted to reflect an amount equal to incentive distributions and an amount required to reflect

depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. Net income per unit was determined as follows:

	Year ended December 31,		
	2000	1999	1998
Net income	$ 60.2	$ 78.7	$ 88.5
Net income allocated to General Partner	(0.6)	(0.8)	(0.9)
Adjusted to reflect:			
Incentive distributions and historical cost basis depreciation	(8.2)	(8.3)	(7.1)
	(8.8)	(9.1)	(8.0)
Net income allocable to Common Units	$ 51.4	$ 69.6	$ 80.5
Weighted average units outstanding (millions)	28.9	28.0	26.2
Net income per unit	$ 1.78	$ 2.48	$ 3.07

5. Property, Plant and Equipment, Net

	Average Depreciation Rates	December 31, 2000	December 31, 1999
Land	—	$ 6.4	$ 6.4
Rights-of-way	3.8%	109.8	110.4
Pipeline	3.6%	957.9	957.1
Pumping equipment, buildings and tanks	4.2%	470.1	458.2
Vehicles, office and communications equipment	9.6%	34.3	31.6
Construction in progress	—	10.0	4.7
		1,588.5	1,568.4
Accumulated depreciation		(306.6)	(247.1)

	$ 1,281.9	$ 1,321.3

Revised depreciation rates were approved by the Federal Energy Regulatory Commission, effective January 1, 1999, better representing the expected remaining service life of the pipeline system and coinciding with the in-service date for the Partnership's system expansion programs. Prior to this change, the average depreciation rate for rights-of-way was 3.6%, pipeline was 4.1%, pumping equipment, buildings and tanks was 4.6% and vehicles, office and communication equipment was 13.9%. The change in depreciation rates resulted in 1999 depreciation expense being $7.1 million, or $0.25 per unit, lower than it would have been utilizing the prior rates.

6. Debt

	December 31,	
	2000	1999
First Mortgage Notes	$ 310.0	$ 310.0
Revolving Credit Facility Agreement	190.0	275.0
Senior Unsecured Notes, Net	299.3	199.5
	$ 799.3	$ 784.5

First Mortgage Notes

The First Mortgage Notes ("Notes") are secured by a first mortgage on substantially all of the property, plant and equipment of the Partnership and are due and payable in ten equal annual installments beginning 2002. The interest rate on the Notes is 9.15% per annum, payable semi-annually. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain issuance tests. The General Partner believes these issuance tests will not negatively impact the Partnership's ability to finance future expansion projects. Under the Note Agreements, the Partnership is permitted to make cash distributions not more frequently than quarterly in an amount not to exceed Available Cash (Note 3) for the immediately preceding calendar quarter.

Revolving Credit Facility Agreement

The Partnership has a $350.0 million ($205.0 million prior to June 18, 1998) Revolving Credit Facility Agreement scheduled to mature during September 2005. Each year, on the anniversary date of the facility, the current maturity date may be extended by one year subject to the approval of the lending banks. Upon drawdown, the loans are secured by a first lien on the mortgaged property that ranks equally with the Notes or may be fully collateralized with U.S. or Canadian government securities. The facility contains restrictive covenants substantially identical to those in the Note Agreements, provides for borrowing at variable interest rates and has a facility fee of 0.10% (1999—0.085%) per annum on the entire $350.0 million. At December 31, 2000, $190.0 million of the facility was utilized and is classified as long-term debt (1999—$275.0 million). The interest rate on loans averaged 6.7% (1999—5.4%; 1998—5.8%) for the year and was 6.2% at the end of 2000 (1999—5.9%).

Senior Unsecured Notes

On November 21, 2000 the Operating Partnership issued $100.0 million of Senior Unsecured Notes which carry an interest rate of 7.9% and mature in 2012. On October 1, 1998, the Operating Partnership issued a total of $200.0 million Senior Unsecured Notes in two tranches of $100.0 million. The first tranche carries an interest rate of 7.00% and matures in 2018. The second tranche carries an interest rate of 7.125% and matures in 2028. Interest on all tranches is payable semi-annually. The Senior Unsecured Notes do not contain any financial tests restricting the issuance of additional indebtedness.

Interest

Interest expense is net of amounts capitalized of $0.3 million (1999—$4.4 million; 1998—$25.5 million) and includes amounts related to accrued rate refunds of $0.7 million in 1999 and $2.1 million in 1998. Interest paid amounted to $59.4 million (1999—$56.1 million; 1998—$44.4 million).

Debt Service Reserve

Under the terms of the First Mortgage Notes and the Revolving Credit Facility, the Partnership is required to establish at the end of each quarter a debt service reserve in an amount equal to 50% of the prospective debt service payments for the immediate following calendar quarter. At December 31, 2000, this debt service reserve was $0.8 million (1999—$1.1 million).

7. Related Party Transactions

The Partnership, which does not have any employees, uses the services of the General Partner and its affiliates for managing and operating its pipeline business. These services, which are reimbursed at cost in accordance with service agreements, amounted to $30.3 million (1999—$34.3 million; 1998—$34.9 million) and are included in operating and administrative expenses. At December 31, 2000, the Partnership has accounts receivable from the General Partner and affiliates of $1.5 million. At December 31, 1999, the Partnership had accounts payable from the General Partner and affiliates of $1.7 million.

The Partnership had entered into an easement acquisition agreement with Enbridge Holdings (Mustang) Inc. ("Enbridge Mustang"), an affiliate of the General Partner. Enbridge Mustang acquired certain real property for the purpose of granting pipeline easements to the Partnership for construction of a new pipeline, completed during 1998, by the Partnership from Superior, Wisconsin to Chicago, Illinois. In order to provide for these real property acquisitions by Enbridge Mustang, the Partnership had made non-interest bearing cash advances to Enbridge Mustang. As Enbridge Mustang disposes of the real property, the advances are repaid. The advances amounted to $5.9 million at December 31, 2000 (1999—$7.5 million). Under the terms of the agreement, the Partnership will reimburse Enbridge Mustang the net cost of acquiring, holding and disposing of the real property.

In late March 1999, the Partnership borrowed $25.0 million from the General Partner under an uncommitted lending facility authorized by the Board of Directors of the General Partner. The loan was repaid in early April 1999 and had an interest rate of 7.75%. The General Partner is authorized to make loans from time to time to the Partnership, on an uncommitted basis, in an amount not to exceed $200.0 million.

The Partnership has entered into an agreement with Tidal Energy Marketing Inc. ("Tidal") of which Enbridge Inc. has a 50% interest. Tidal is actively engaged in the business of crude oil and condensate marketing, transportation, storage and trading and providing related services. The agreement gives Tidal the ability to act as the Partnership's agent in the leasing of the Partnership's terminalling and storage facility in Schererville, Indiana, known as the Hartsdale Terminal, consisting of nine 100,000 bbl nominal capacity tanks and related facilities. The Partnership pays Tidal a monthly fee

which includes 50% of the distributable proceeds from the tank leases. In 2000, the Partnership paid Tidal a total of $0.1 million.

8. Major Customers

Operating revenue received from major customers was as follows:

	Year ended December 31,		
	2000	1999	1998
BP Canada Energy Company	$ 69.6	$ 71.9	$ 59.5
Mobil Oil Company of Canada Ltd	$ 48.3	$ 42.2	$ 40.0
PDV Midwest	$ 33.7	$ 23.7	$ 21.3
Imperial Oil Limited	$ 23.3	$ 33.3	$ 33.6

The Partnership has a concentration of trade receivables from companies operating in the oil and gas industry. These receivables are collateralized by the crude oil and other products contained in the Partnership's pipeline and storage facilities.

9. Accrued Rate Refunds and Related Interest

In October 1996, FERC approved a settlement agreement between the Partnership and customer representatives on all then outstanding contested tariff rates. The agreement resulted in an approximate tariff rate reduction of 6% and total rate refunds and related interest of $120.0 million through the effective date of October 1, 1996. Refunds required under the agreement began in 1996 with $41.8 million repaid during the fourth quarter of 1996, with the balance being repaid through a 10% reduction on future rates. Interest was accrued on the unpaid balance based on the 90-day Treasury Bill rate. Effective November 22, 1999, the 10% reduction in tariff rates was removed and during December 1999, the $120.0 million and related interest was fully repaid.

During 1999, refunds of $29.4 million (1998—$28.5 million), including the related interest, were made to customers by the Partnership.

10. Contingencies

Environment

The Partnership is subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid pipeline operations and the Partnership could, at times, be subject to environmental cleanup and enforcement actions. The General Partner manages this environmental risk through appropriate environmental policies and practices to minimize the impact to the Partnership. To the extent that the Partnership is unable to recover environmental costs in its rates (if not recovered through insurance), the General Partner has agreed to indemnify the Partnership from and against any costs relating to environmental liabilities associated with the pipeline system prior to its transfer to the Partnership in 1991. This excludes any liabilities resulting from a change in laws after such transfer. The Partnership continues to voluntarily investigate past leak sites for the purpose of assessing whether any remediation is required in light of current regulations, and to date no material environmental risks have been identified.

Oil in Custody

The Partnership transports crude oil and NGL owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 14 million barrels, virtually all of which is owned by the Partnership's customers. Under terms of the Partnership's tariffs, losses of crude oil not resulting from direct negligence of the Partnership may be apportioned among its customers. In addition, the Partnership maintains adequate property insurance coverage with respect to crude oil and NGL in the Partnership's custody.

11. Financial Instruments

Fair Value of Financial Instruments

The carrying amounts of cash equivalents approximate fair value because of the short-term maturities of these investments.

Based on the borrowing rates currently available for instruments with similar terms and remaining maturities, the carrying value of borrowings under the Revolving Credit Facility approximate fair value, the fair value of the First Mortgage Notes approximates $346.5 million (1999—$334.1 million) and the fair value of the Senior Unsecured Notes approximates $290.3 million (1999—$177.2 million). Due to defined contractual make-whole arrangements, refinancing of the First Mortgage Notes and Senior Unsecured Notes would not result in any financial benefit to the Partnership.

Fair Value of Off Balance Sheet Financial Instruments

At December 31, 2000, the Partnership had interest rate swap agreements with a notional principal amount of $50.0 million maturing July 21, 2002, to hedge its exposure to movements of future interest rates on its borrowings under the Revolving Credit Facility. The fair value of the agreements is approximately ($0.1) million, reflecting the estimated amount that the Partnership would have to pay to terminate the contracts at the year end date.

To hedge its exposure to movements of future exchange rates for payments in Canadian dollars to the General Partner's Canadian affiliates for committed operating and management services to be provided during 2001, the Partnership has entered into average forward contracts. The contracts provide for the Partnership to buy a total of Canadian $19.9 million for U.S. $13.1 million. At December 31, 2000, the fair value receivable of the contracts is approximately $0.1 million, reflecting the estimated amount that the Partnership would receive to terminate the contracts at the year-end date.

12. Adoption of New Accounting Standard

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities." This Statement requires that all derivatives be recognized at fair value in the balance sheet and all changes in fair value be recognized currently in earnings or deferred as a component of other comprehensive income, depending on the intended use of the derivative, its resulting designation and its effectiveness. The Partnership plans to adopt this Statement in 2001, as required. This statement is not expected to have a material effect on the Partnership's financial statements due to the small amount of derivative activity currently within the Partnership.

LAKEHEAD PIPE LINE PARTNERS, L.P.

SUPPLEMENTARY INFORMATION (UNAUDITED)

SELECTED QUARTERLY FINANCIAL DATA

(dollars in millions, except per unit amounts)

2000 Quarters	First	Second	Third	Fourth	Total
Operating revenue	$ 78.8	$ 78.3	$ 74.9	$ 73.6	$ 305.6
Operating income	$ 33.3	$ 31.2	$ 29.0	$ 23.0	$ 116.5
Net income	$ 20.1	$ 16.5	$ 14.2	$ 9.4	$ 60.2
Net income per unit(1)	$ 0.62	$ 0.49	$ 0.42	$ 0.25	$ 1.78

1999 Quarters	First	Second	Third	Fourth	Total
Operating revenue	$ 74.0	$ 80.4	$ 79.6	$ 78.6	$ 312.6
Operating income	$ 33.2	$ 35.4	$ 33.4	$ 28.3	$ 130.3
Net income	$ 21.7	$ 22.5	$ 19.8	$ 14.7	$ 78.7
Net income per unit(1)	$ 0.75	$ 0.71	$ 0.60	$ 0.42	$ 2.48

(1)

The General Partner's allocation of net income has been deducted before calculating net income per unit.

QuickLinks

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 21

LAKEHEAD PIPE LINE PARTNERS, L.P.
PRINCIPAL SUBSIDIARIES

The Registrant's principal subsidiary is Lakehead Pipe Line Company, Limited Partnership, a Delaware limited partnership, in which the Registrant has a 99% limited partner interest.

QuickLinks

LAKEHEAD PIPE LINE PARTNERS, L.P. PRINCIPAL SUBSIDIARIES

QuickLinks -- Click here to rapidly navigate through this document

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the registration statement on Form S-3 (No. 333-59597) of Lakehead Pipe Line Partners, L.P. of our report dated January 12, 2001 relating to the financial statements, which appear in this Form 10-K.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 12, 2001