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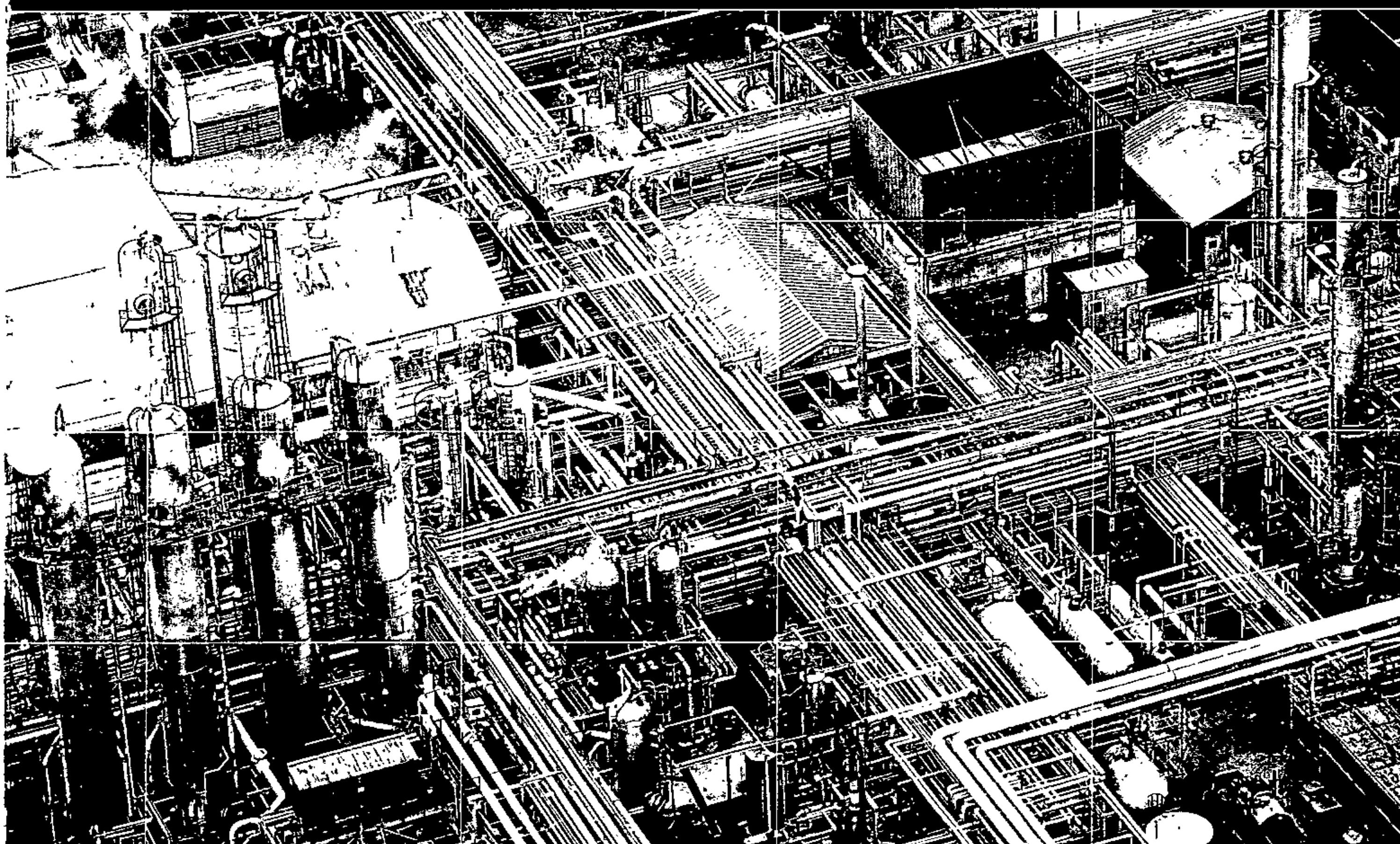
KEYERA

Keyera Capturing Opportunities



Versatile, long-life assets • Strategically located • Integrated business lines • New business opportunities

06 Annual Report

KEYERA

Corporate Profile

Keyera Facilities Income Fund operates one of the largest natural gas midstream businesses in Canada. Our three business lines consist of: natural gas gathering and processing; the processing, transportation, and storage of natural gas liquids (NGLs) and crude oil; and NGL marketing and crude oil midstream services.

Our facilities are strategically located in natural gas production areas on the western side of the Western Canadian Sedimentary Basin. Keyera's NGL and crude oil infrastructure includes pipelines, terminals, processing plants, and storage facilities in Edmonton and Fort Saskatchewan, Alberta. Keyera also markets propane, butane, and condensate to customers across North America.

Keyera trades on The Toronto Stock Exchange under the symbols KEY.UN and KEY.DB.

This Annual Report contains forward looking information which is based on management's current beliefs and assumptions, but actual events or results may differ materially. For further information, readers are referred to Keyera's filings with Canadian provincial securities commissions which are available on SEDAR (www.sedar.com).

Contents

Front Cover Photo: *The Rimbey Gas Plant, Keyera's largest energy complex, is capable of processing up to 422 million cubic feet per day of raw natural gas. As well, it produces specification propane, butane and condensate, frac oil and liquefied carbon dioxide.*

GATHERING AND COMPRESSION Our business begins with the collection of customers' raw gas in our network of gathering pipelines for delivery to Keyera's processing plants. In some cases, raw gas requires compression to ensure that it enters the gathering systems or gas plants at sufficient pressure. Keyera charges customers a fee for the use of our pipelines and compressors.

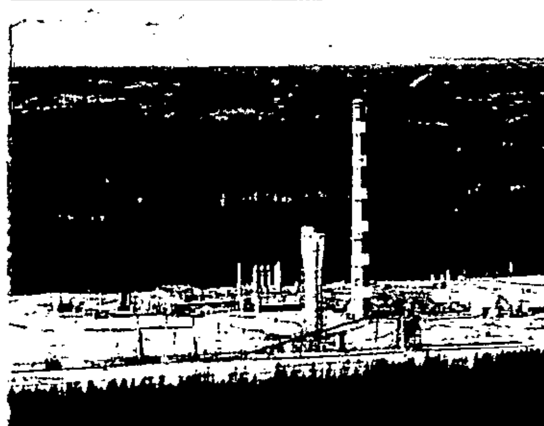
NATURAL GAS PROCESSING Through the application of physical and chemical processes, commercially valuable products, such as sales gas and natural gas liquids (NGLs), are separated from the raw gas stream. Impurities, such as water, hydrogen sulphide and carbon dioxide, are removed and disposed of. Keyera charges customers a fee for these processing services.

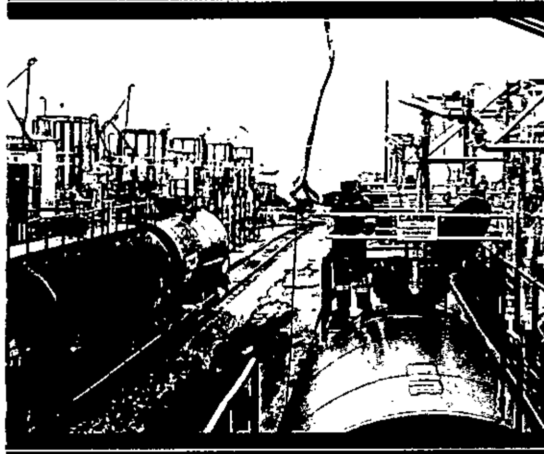
NGL PROCESSING We separate the NGL mix that is recovered from the raw gas stream during the gas processing stage into products such as propane, butane and condensate before they are sold to end-use customers. Keyera charges customers a fee for these services.

NGL TRANSPORTATION AND STORAGE Propane, butane and condensate are delivered to end-use markets by pipeline or on trucks or railcars from loading terminals located at our processing and storage facilities. The NGL mix and sales products are often stored in Keyera's underground storage caverns for future processing or sale. Keyera charges customers a fee for these services.

NGL MARKETING AND CRUDE OIL MIDSTREAM
Our marketing professionals purchase NGLs from approximately 200 natural gas producers and sell to more than 100 customers. We own and operate three sales terminals and manage a fleet of over 600 railcars that provide access to retail and industrial customers across North America. We also manage a crude oil midstream business, utilizing Keyera facilities to enhance value. Keyera earns a margin on the sale of these products.

Keyera at a Glance

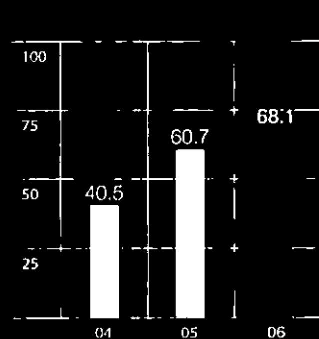




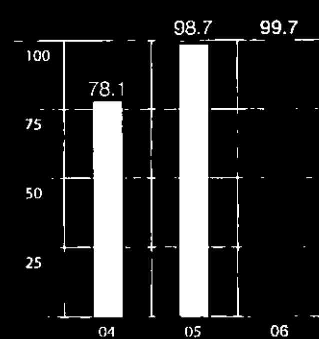
Financial Highlights

	2006	2005	2004
Revenues *($ millions)*	1,368.5	1,187.6	937.4
Net earnings *($ millions)*	68.1	60.7	40.5
Capital expenditures *($ millions)*	73.9	52.9	29.8
Distributable cash flow [1] *($ millions)*	99.7	98.7	78.1
Per unit *($)*	1.65	1.67	1.50
Distributions to unitholders *($ millions)*	86.6	78.5	59.5
Per unit *($)*	1.43	1.33	1.14

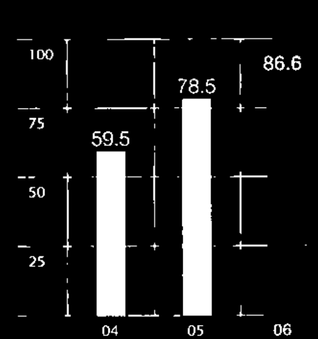
Net Earnings
($ millions)



Distributable Cash Flow [1]
($ millions)



Distributions to Unitholders
($ millions)



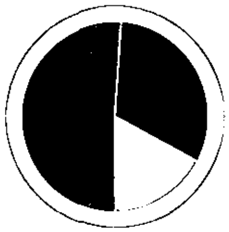
[1] *See "Note regarding Non-GAAP Financial Measures" in Keyera's 2006 MD&A. 2004 distributable cash flow is shown before deducting Fund expenses.*

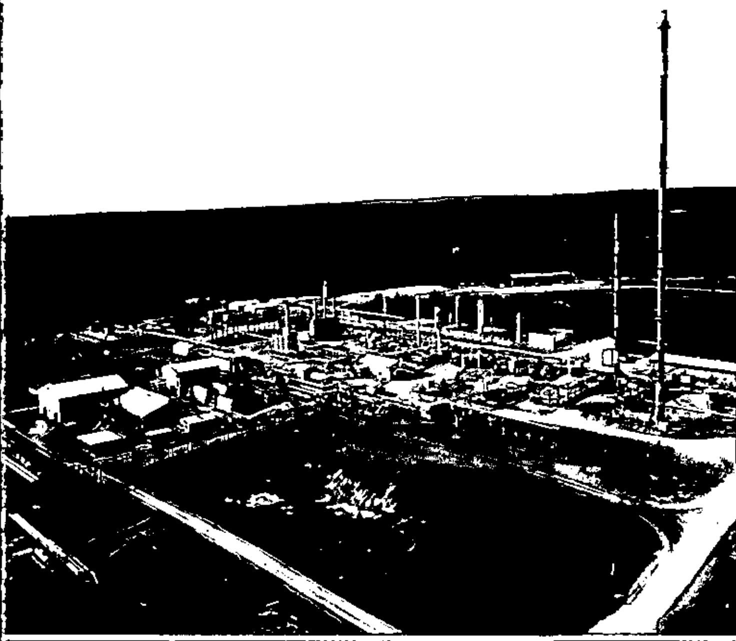
Note: 2004 reflects Keyera Energy Partnership results and are included for comparison purposes. Distributable cash flow is not a standard measure under Canadian generally accepted accounting principles and therefore may not be comparable with the calculation of similar measures for other entities.

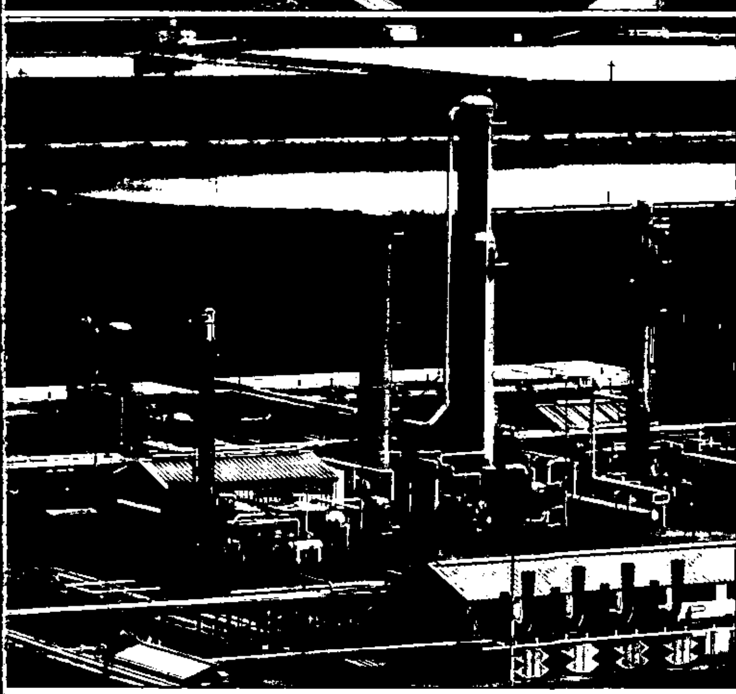
Keyera's activities are conducted through three business segments

Segment Contribution
($ millions)

Gathering and Processing	$73.6
NGL Infrastructure	$45.1
NGL Marketing and Crude Oil Midstream	$24.7







Our Strengths

OUR COMPETITIVE ADVANTAGE IN GATHERING AND PROCESSING COMES FROM:

- Large, well-positioned facilities with broad capture areas and high barriers to entry
- Available unutilized capacity, providing the ability to accommodate additional throughput from producers
- Processing flexibility, with over 90% of capacity able to process sour gas and extract NGLs
- Expertise in operating large, sour gas processing facilities in a safe, responsible manner

KEYERA'S NGL INFRASTRUCTURE ASSETS ARE:

- Strategically located in the Edmonton/Fort Saskatchewan area, a major North American energy hub
- Fully integrated with our gathering and processing and marketing businesses, allowing us to enhance value throughout the midstream value chain
- Well positioned to provide storage and logistics services to support the NGL and heavy oil sectors

OUR NGL MARKETING AND CRUDE OIL MIDSTREAM BUSINESS CREATES VALUE BY:

- Maintaining geographic and customer diversity
- Delivering propane to end-use markets across North America
- Providing butane and condensate to crude oil markets in western Canada
- Employing logistics expertise across niche markets
- Optimizing crude oil streams at a number of Keyera facilities

Keyera at a Glance

2006 Achievements	Key Opportunities	
TO ENHANCE THE SERVICES WE PROVIDE, WE: • Constructed the 48-kilometre Caribou North Gas Gathering System • Expanded the Caribou gas plant inlet capacity by 63% to 65 million cubic feet per day • Constructed the Aurora pipeline • Increased our ownership in the Gull Lake and Medicine River pipelines • Completed numerous compression and optimization projects	**WE HAVE OPPORTUNITIES FOR CONTINUED GROWTH BECAUSE:** • Long-term fundamentals suggest that demand for western Canadian natural gas will continue • Our facilities are strategically located in the western part of the Western Canadian Sedimentary Basin where significant geological potential exists • Drilling is ongoing in the areas surrounding our facilities • Producers have discovered new oil and gas reserves and require gathering and processing infrastructure to bring their products to market	GATHERING AND PROCESSING
TO CREATE ADDITIONAL VALUE THROUGH OUR NGL INFRASTRUCTURE ASSETS, WE: • Expanded our rail facility at the Edmonton Terminal to deliver up to 10,000 barrels per day of condensate into the Alberta market • Enhanced our NGL storage capabilities by completing construction of a new 3.9 million barrel brine pond at Fort Saskatchewan • Secured additional fee-for-service storage contracts	**OVER TIME, OIL SANDS DEVELOPMENT WILL PROVIDE THE OPPORTUNITY TO:** • Further expand our existing facilities at Edmonton and Fort Saskatchewan • Provide additional processing, storage, blending and logistics services • Import required condensate and other products into the Alberta market to meet growing diluent requirements	NGL INFRASTRUCTURE
TO ENHANCE OUR COMPETITIVE ADVANTAGE, WE: • Acquired three propane sales terminals in the U.S., expanding our customer base and the markets we serve • Increased NGL sales volumes to over 50,000 barrels per day • Developed crude oil midstream facilities at various Keyera locations	**OUR STRATEGIC FACILITIES WILL ALLOW US TO:** • Access and deliver products into new niche markets throughout North America • Source, transport and deliver condensate into the Edmonton/Fort Saskatchewan hub for the oil sands sector • Grow our crude oil midstream business by utilizing additional Keyera locations to enhance crude oil value	NGL MARKETING AND CRUDE OIL MIDSTREAM

Our directors are actively engaged in working with management to set long-term goals and develop Keyera's strategic direction.

Keyera Directors

Left to right:
Michael B.C. Davies
Wesley R. Twiss
Robert B. Catell
Jim V. Bertram
E. Peter Lougheed
William R. Stedman
Nancy M. Laird
H. Neil Nichols

Chairman's Message

This year marks another very successful year for Keyera. Since becoming an income trust in 2003, we have invested over $400 million to grow our business in Canada. We have increased distributions to our unitholders by 31%. And we have contributed to economic growth and increased employment in the communities in which we operate. Going forward, we are well positioned to play a significant role in the development and future growth of the oil and gas sector in Alberta.

During 2006, Keyera spent a record $71 million on capital projects to grow all three segments of our business. These projects, the majority of which have already created value for unitholders by delivering incremental cash flow, position Keyera to benefit from future industry activity.

Long-term natural gas fundamentals remain strong and Keyera is poised to benefit from ongoing natural gas drilling in the Western Canadian Sedimentary Basin. Industry observers also expect oil sands development to rise dramatically over the next decade. Much of the bitumen from these developments is expected to be upgraded in the Edmonton/Fort Saskatchewan area where Keyera's NGL facilities are located and where we have recently expanded our capability to provide logistics and diluent storage services.

As we prepare for this exciting future, Keyera's board and management remain focused and disciplined. Through involvement at the board level and on the three permanent committees, your directors are actively engaged in working with management to set long-term goals and develop strategic direction. We are committed to developing and supporting policies, practices and procedures that meet the standards expected by our unitholders. I would like to thank my fellow directors for their contributions over the past year.

In addition, I would like to thank the management and employees of Keyera for their dedication to operating our facilities in a safe and environmentally responsible manner while delivering attractive returns to unitholders. Congratulations, also, to Jim Bertram and his team for being recognized by the Alberta chapter of the Canadian Investor Relations Institute as its 2006 Management Team of the Year. This award is presented to management teams who demonstrate leadership in investor communications, disclosure, corporate reporting, and governance.

I am excited by the benefits that Alberta's positive business climate and vibrant economy will provide to the people of Alberta and to all Canadians. Businesses that have the vision and capability to capture opportunities will drive Alberta's future growth, and I am confident that Keyera will be among them. With strategically located assets, a strong operational focus, an experienced team of professionals, and exceptional internal growth opportunities, Keyera's future looks very bright.

On behalf of the Board of Directors,

E. Peter Lougheed
Chairman of the Board

March 1, 2007

President's Message

It gives me great pleasure to provide an update on Keyera's activities over the past year. Significant accomplishments in all areas of our business made 2006 a tremendous year.

It was a year in which we continued to deliver value to unitholders by generating cash flows from new projects and positioning our core,businesses to capture future opportunities.

Keyera's net earnings in 2006 were $68.1 million, 12% higher than last year. Distributable cash flow[1] was $99.7 million, or $1.65 per basic unit, despite the additional costs of our active maintenance program. We invested $71 million of growth capital in 2006, completing major projects in each of our three business lines.

SUCCESSFUL EXECUTION OF OUR BUSINESS STRATEGY

Since our initial public offering almost four years ago, we have executed a consistent strategy to deliver value to unitholders over the long-term. Applying focus and discipline to our business affairs has resulted in stable and growing distributions to unitholders. 2006 was an active and rewarding year, and I am very pleased with how our growth projects began contributing to cash flow immediately and, perhaps more important, how they position us to capture new opportunities in the future. I continue to be very excited about the ongoing potential I see in each of our business lines.

[1] *See "Note regarding Non-GAAP Financial Measures" in Keyera's 2006 MD&A.*

BUSINESS FUNDAMENTALS REMAIN POSITIVE

As industry fundamentals are a key metric for Keyera's overall success, we are encouraged by the positive long-term outlook for natural gas. Despite a decline in some natural gas drilling activity caused by softening natural gas prices in 2006, our view is that drilling activity in the areas surrounding our plants will remain strong.

Key North American Supply Basin

We share the view of many industry observers that North American demand for natural gas will remain strong and that natural gas will continue to be the fuel of choice for consumers. While alternative sources of natural gas will continue to be developed in the future, we believe that the Western Canadian Sedimentary Basin will be a key supply basin for many years. This basin is the second largest source of natural gas in North America, supplying one-quarter of continental demand. Western Canada has sufficient excess pipeline capacity to deliver new gas to the key demand centers on the continent. Growing North American demand is expected to sustain high levels of drilling activity, while growing demand over the longer-term should encourage producers to explore for new natural gas reserves.

Location Mitigates Effect of 2006 Drilling Slowdown

In 2006, an excess of gas in storage caused short-term natural gas supply to exceed demand and North American natural gas prices to soften somewhat. By mid-year, drilling activity associated with shallow gas and coal bed methane projects in western Canada began to decline as lower prices affected producer economics. Keyera's areas of operations were not significantly affected by this decline in drilling.

2006 – SUCCESSFUL EXECUTION OF BUSINESS STRATEGY

Expanded the brine storage capacity at our Fort Saskatchewan facility by 3.9 million barrels by constructing a new surface brine pond. The brine pond allows us to better utilize the capacity of our NGL storage caverns, thereby increasing fee-for-service revenue at the facility.

Constructed natural gas gathering pipelines to our Caribou gas plant in northeastern British Columbia and to our Gilby gas plant in west central Alberta. These pipelines generate tariff revenue and increase plant processing utilization. The new pipelines also allow producers to develop new production areas.

Completed scheduled maintenance at three natural gas processing plants. These turnarounds allowed Keyera personnel to complete various inspections and undertake required maintenance and repairs. This work positions the plants to continue to operate reliably and efficiently for many years.

The majority of Keyera's facilities are located on the western side of the basin, where drilling activity remained robust in 2006. Producers active in this area are often targeting deeper geological horizons. Deeper wells require longer lead times to drill, complete, and tie-in, but have higher potential for larger reserves yielding higher cash flows. As a result, the economics of these types of projects are less affected by short-term fluctuations in natural gas prices and producers are not as likely to suspend activity during periods of short-term price softness.

Drilling activity in 2006 made this evident. In the British Columbia and foothills front regions, there were 1,404 and 2,804 wells drilled, 2% more than last year and 15% and 32% more, respectively, than in 2004. In the central Alberta region, 2,931 wells were drilled, 5% lower than last year, due to a slowdown in shallow well drilling.

A number of producers are pursuing active drilling programs on the undeveloped lands north of the Caribou gas plant in northeastern British Columbia. Our Caribou North Gas Gathering System, built in early 2006, extends north from the plant for 48 kilometres and, with a capture area of over 1,000 square kilometres, provides needed pipeline infrastructure for producers in the area. We undertook a major plant expansion in June to process additional volumes, and throughput now exceeds the original capacity.

In the Pembina area of Alberta, producers continue to develop sour crude oil from the Nisku zone. This oil contains considerable amounts of sour natural gas that are delivered to Keyera plants in the area for processing. Keyera's Brazeau River gas plant has seen throughputs rise throughout 2006 as producers resolved technical and regulatory issues. From the location of new wells, it appears that producers believe the areal extent of the Nisku development is larger than originally thought and new wells continue to be licensed.

Throughput also increased in 2006 from wells southwest of the Strachan gas plant in west central Alberta. Several producers are active in this area and we are seeing a number of wells being drilled to test geologically attractive zones.

In 2006, the focus at our Rimbey and Gilby gas plants was on leveraging existing assets to create incremental value. Through the completion of a number of compression and pipeline projects, throughputs increased at each plant by 6% and 16% respectively.

Oil Sands Activity Offers Significant Potential

In northeastern Alberta, oil sands development is presenting opportunities to provide services to producers at our facilities in Fort Saskatchewan and Edmonton. Industry observers forecast that over 30 new oil sands projects will be completed in the next 10 to 15 years, increasing bitumen and heavy oil production by more than 4 million barrels per day.

Bitumen from the oil sands requires upgrading to extract the crude oil from the associated impurities. While upgrading will be done on site for the majority of the surface mining projects, bitumen from most of the in situ projects is expected to be delivered by pipeline for processing at upgraders located in Fort Saskatchewan and elsewhere.

We expect the demand for logistics services around the Edmonton/Fort Saskatchewan area to increase in tandem with the increase in production. For bitumen to flow in pipelines, it must be diluted with a lighter product, such as condensate, to lower its viscosity. Increasing amounts of diluent will be required, along with blending, storage, and pipeline services. In addition, producers will need logistics and storage services to manage increasing quantities of upgraded crude oil and refined products before they are shipped to downstream markets.

Expanded the rail rack at our Edmonton pipeline and terminal hub to enable the offloading of products, particularly condensate, for delivery into the Alberta market. This expansion allows us to utilize existing infrastructure and provide additional services.

Acquired three propane rail and truck terminals in the U.S. These distribution terminals allow us to expand our wholesale customer base and diversify the geographic markets we serve. Vertical integration with our NGL marketing business increases our flexibility and helps mitigate risk.

Keyera is well positioned to provide these goods and services to the oil sands sector, with 8.6 million barrels of underground storage, rail and truck terminals, pipelines and pipeline connections. These facilities are located in the Edmonton/ Fort Saskatchewan area, where the majority of the upgraders and oil pipeline infrastructure will be located. Over the last year, we have worked with a number of oil sands producers, pipeline companies, and other service providers to understand their requirements, and we will continue work to capture future opportunities as this production comes on stream.

To position Keyera for this increased demand, we completed two major projects in the Edmonton/Fort Saskatchewan area in 2006. At our Fort Saskatchewan facility, we constructed a new brine pond to better utilize our underground storage capacity. The increased capacity provides greater operating flexibility and allowed us to immediately contract for additional storage.

We expanded the rail rack at our Edmonton terminal and pipeline hub to allow for the offloading of condensate for sale as diluent in Alberta. This project gives our marketing team an alternative source of diluent and provides additional services and flexibility to our NGL Infrastructure business.

FOCUSED STRATEGIC DIRECTION

Over the past eight years, we have developed a clear vision for the business: to deliver steady value growth built around sustainable competitive energy facilities. We will achieve this vision by continuing to execute a three-phase strategy:

- First, we will work to increase plant utilization and encourage facility consolidation by providing superior customer service, modifying plants and extending the reach of our gathering pipelines.
- Second, we will pursue expansion and optimization opportunities in and around our processing facilities and enhance and expand our strategic assets in the Edmonton/ Fort Saskatchewan region. This will increase the profitability of our existing business and strengthen our competitive advantage.
- Third, we will selectively pursue acquisition opportunities to grow our asset base, increasing returns to unitholders. We will stay focused on acquisitions where we see attractive long-term potential and where there are competitive advantages through our operational expertise, barriers to entry, or synergy with existing operations.

Our strategic direction has not changed substantially in the eight years that we have been operating these assets, and we believe that this strategy will continue to deliver long-term value for our unitholders.

In 2007, we anticipate capital spending of $40 to $60 million on new growth projects to generate incremental cash flows and provide enhanced services to our customers.

TAX CHANGES HAVEN'T CHANGED OUR BUSINESS DIRECTION

On October 31, the Canadian Government unexpectedly announced its intention to implement a tax on the distributions of Canadian income trusts. The announcement had a significant negative impact on the market price of Keyera units. However, I would like to reassure unitholders that despite this, Keyera's business remains strong. With our strategic asset base, experienced people, and abundance of opportunities, I am confident that we will continue to grow our successful energy infrastructure business.

ACKNOWLEDGEMENTS

In 2006, we received a Certificate of Recognition renewal from Alberta Human Resources and Employment for Keyera's performance and commitment to safety. Keyera was also recognized by the Conference Board of Canada for our innovative employee competency training program. As important as financial and operating results are, nothing is more important than the safety of our people, and I am extremely proud that our efforts have been recognized. I would like to thank our employees and contractors for their ongoing commitment to making Keyera facilities safe places to work.

Our success is a direct result of having a strong team that embraces a common vision and works day in and day out to deliver results. From the members of our Board of Directors to each and every employee, I would like to thank you for your enthusiasm and hard work over the past year and I look forward to sharing continued success. Finally, to our unitholders, thank you for your ongoing support of our business strategy and our efforts to create unitholder value today and in the future.

Jim V. Bertram
President and Chief Executive Officer

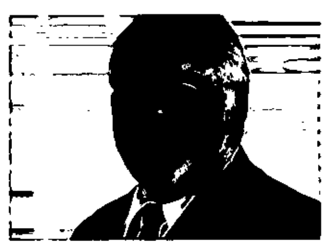
March 1, 2007

Keyera Officers









Jim V. Bertram
President and
Chief Executive Officer

Marzio Isotti
Vice President,
West Central Region

Bradley W. Lock
Vice President, Engineering
and Operational Services

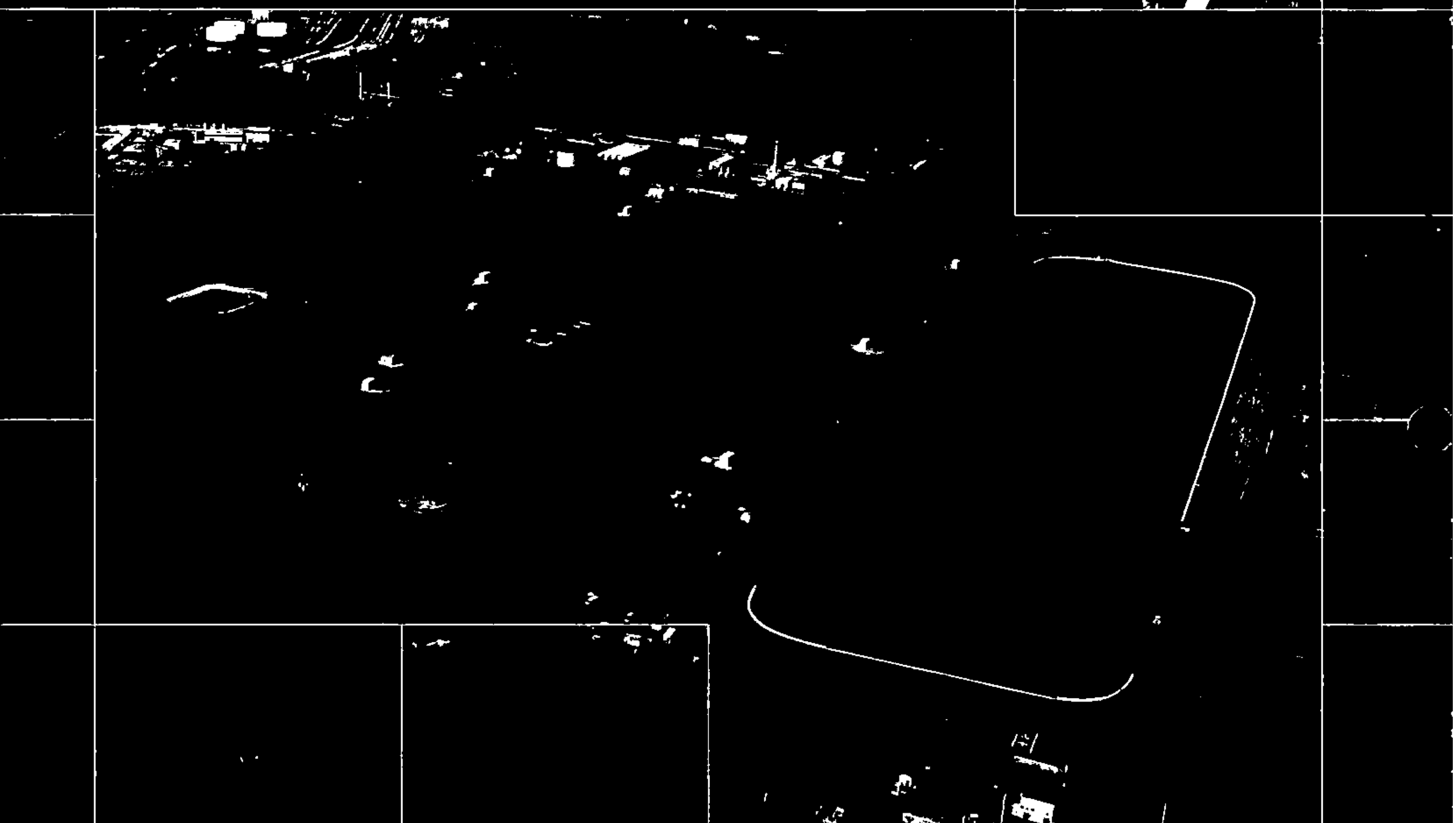
David A. Sentes
Vice President, Comptroller

David G. Smith
Executive Vice President,
Chief Financial Officer
and Corporate Secretary

Steven B. Kroeker
Vice President,
Corporate Development

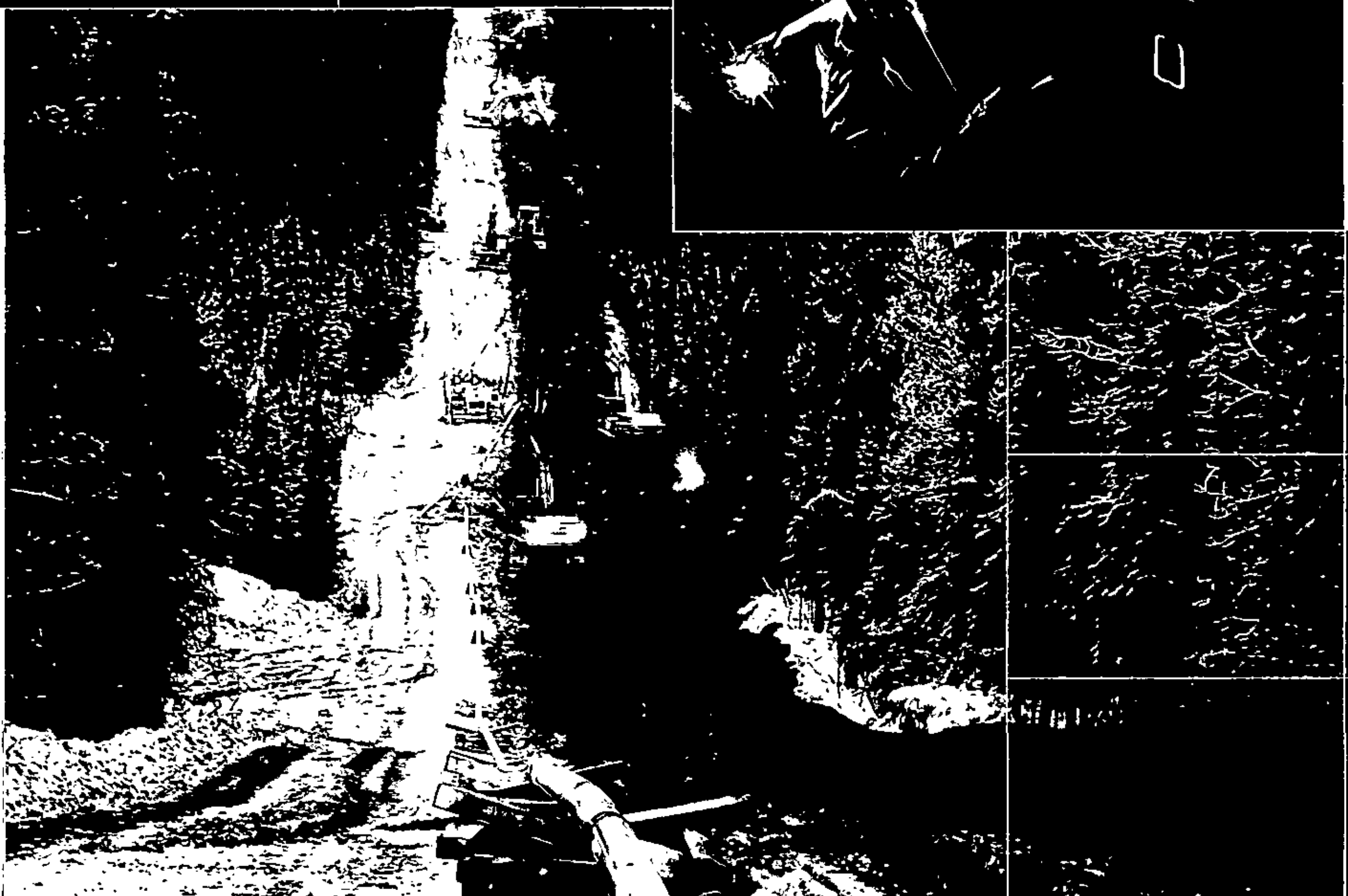
K. Jamie Urquhart
Vice President, Foothills Region

Capturing Opportunities



The size, scope, and strategic location of our assets and the integration of our business lines provide considerable opportunities to grow our business.

Producer activity • Heavy oil development • Expansion and optimization • Customer focused • New services



Top: *Keyera's Edmonton pipeline terminal expanded its service offering with the completion of a new rail rack in 2006.*

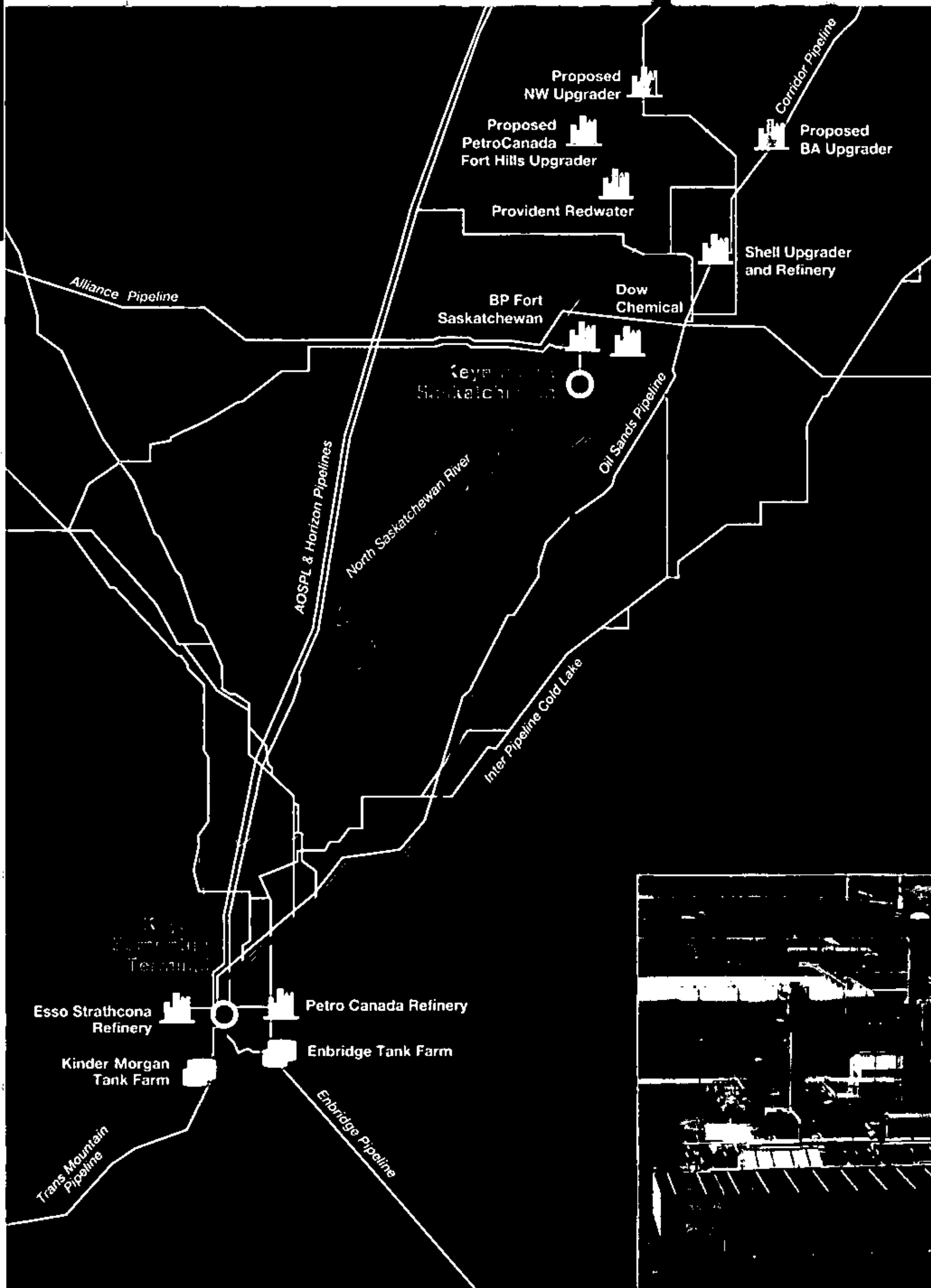
Above: *In January 2006, Keyera opened 1,000 square kilometres of land for natural gas exploration and production with the construction of the Caribou North Gas Gathering System and related plant expansion.*

Bottom Left: *Significant earth work was required to construct the new brine pond, the largest in Fort Saskatchewan.*

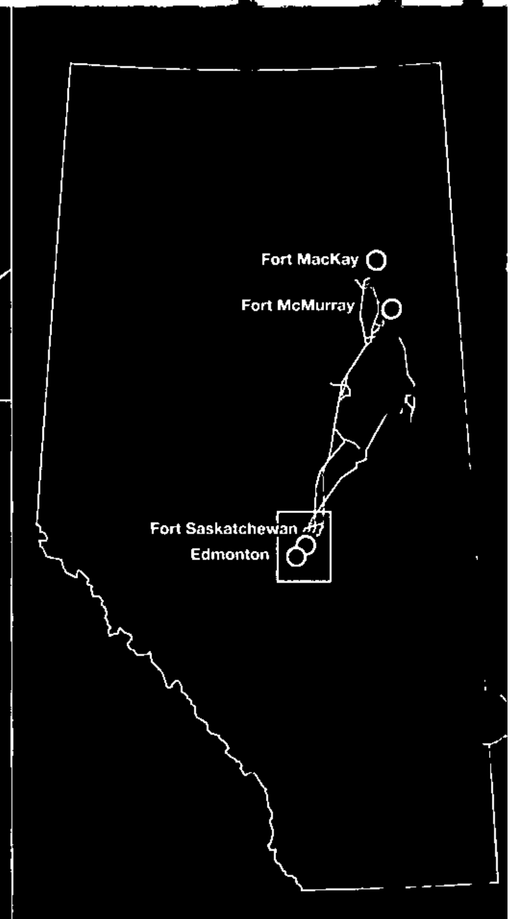
Facing Page: *The completed brine pond provides an additional 3.9 million barrels of surface brine storage and allows for better utilization of our underground NGL storage capacity.*

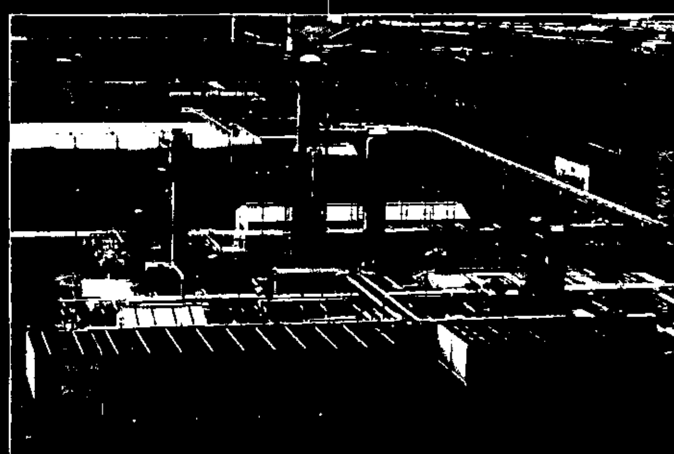
Keyera NGL Infrastructure

Strategically located in Alberta's Industrial Heartland



Connected to the major N.E. Alberta oil sands pipelines





Keyera Facilities

Keyera Pipelines

Other Pipelines

Photo: *Fort Saskatchewan fractionation and storage facility*

NGL Infrastructure

Key midstream services today and in the future

A key element of Keyera's business is our NGL Infrastructure segment, which provides natural gas liquids (NGL) processing, storage, and transportation services to the oil and gas industry. Our four NGL processing plants give us the capacity to process up to 65,000 barrels per day of NGLs. Using our significant pipeline infrastructure and our rail and truck terminals, we deliver NGLs to customers in the Edmonton/Fort Saskatchewan area and throughout North America.

The Fort Saskatchewan area is referred to as "Alberta's Industrial Heartland" because of the concentration of oil and gas and petrochemical facilities in the area. One of only four energy hubs in North America, this is where most NGL and oil feeder pipelines from Alberta and British Columbia converge for processing and storage before products are shipped to downstream markets.

Our NGL services are managed from our pipeline terminal in Edmonton and from our processing and storage facility in Fort Saskatchewan. We also provide NGL storage services, with 8.6 million barrels of underground storage capacity in Fort Saskatchewan.

CAPTURING NEW OPPORTUNITIES

Oil sands activity in the Fort McMurray region is expected to develop at a rapid pace, and industry experts forecast that these projects will deliver over 4 million barrels per day of incremental bitumen production, within the next 15 years. This new production will require upgrading and a number of logistics support services, such as blending, storage, and transportation, before being delivered to end-use markets.

Much of the bitumen upgrading is expected to occur in the Edmonton/Fort Saskatchewan area, which could grow to become the dominant energy hub in North America. Keyera, with logistics and storage facilities located in the heart of this region, is ideally positioned to become a key service provider to the oil sands sector.

Oil sands development is already driving increased demand for condensate for use as diluent and for logistics and storage services. Over the past two years, we have invested $14 million to better utilize our NGL storage capacity and enhance our ability to deliver condensate into Alberta from outside markets.

ROOM TO GROW

We have the capacity to expand and augment our service offering to support growing NGL and oil sands production. There is space at our Edmonton terminal to further expand the rail rack and add above-ground storage tanks. At Fort Saskatchewan, land is available to add approximately 5 million barrels of incremental underground storage.

Keyera is ideally positioned to play a key role over the next several years as the oil sands sector develops. Capturing these opportunities is a key aspect of Keyera's current business strategy.

Enhanced utilization of our storage capacity at Fort Saskatchewan allows us to grow our NGL storage business and positions us to provide additional services to the oil sands sector.

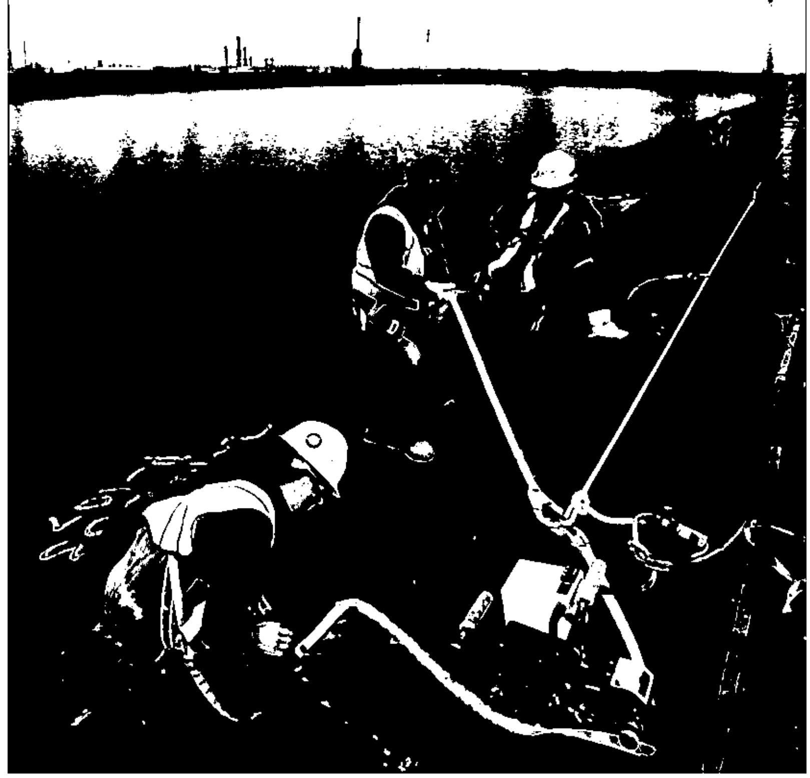
New brine pond increases utilization of NGL storage capacity

With 8.6 million barrels of capacity in underground storage caverns, Keyera is a key storage service provider in the Fort Saskatchewan area. NGLs are produced throughout the year as a by-product of natural gas. However, demand for NGLs, particularly propane, tends to be seasonal, with market demand significantly higher in the winter season. As a result, NGLs are often delivered to storage in the summer and fall months.

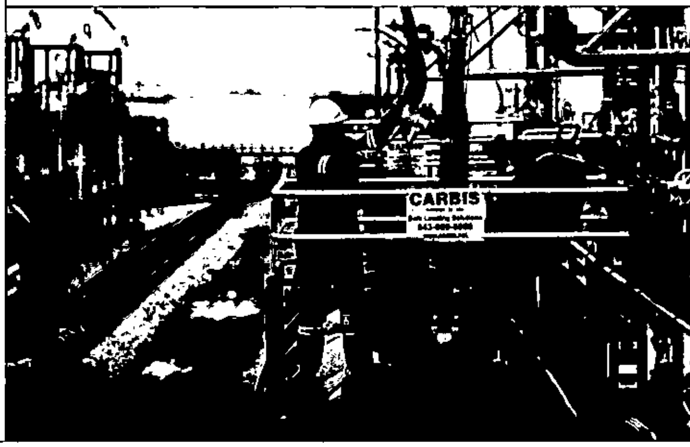
To enable us to fully utilize our underground storage capacity, in 2005 we initiated a $7 million project to construct a new brine pond. Construction was completed in August 2006, in time to meet the demands of the storage season. We are already experiencing growth in our storage business as the higher storage capacities allow us to add new customers.

Brine is used to displace the stored products as they are removed from the underground caverns. As NGLs are pumped into an underground cavern, the brine is displaced and deposited in large, surface level ponds. Keyera's new brine pond provides sufficient above-ground brine storage to handle higher NGL storage levels in the existing caverns, allowing full utilization of our underground storage capacity.

The projected incremental volumes from future oil sands development should result in a corresponding increase in demand for storage services.



With berms measuring up to 12 metres in height, the new brine pond covers 94,000 square metres, the equivalent area of 11 football fields.



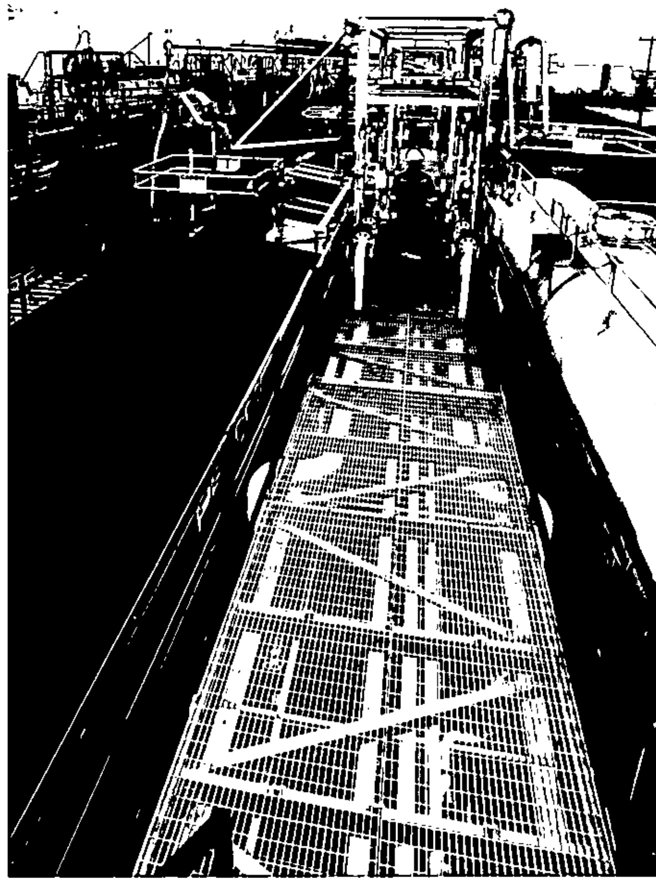
Our rail rack expansion enhances the flexibility of our NGL Infrastructure and allows us to meet the demands of the growing oil sands sector.

Rail rack expansion enhances service offering

Our marketing and logistics expertise, combined with our strategic assets at the Edmonton/Fort Saskatchewan hub, gives us the ability to source, transport, and deliver NGLs to markets throughout North America. With this competitive advantage, Keyera has become an important supplier of condensate in Alberta.

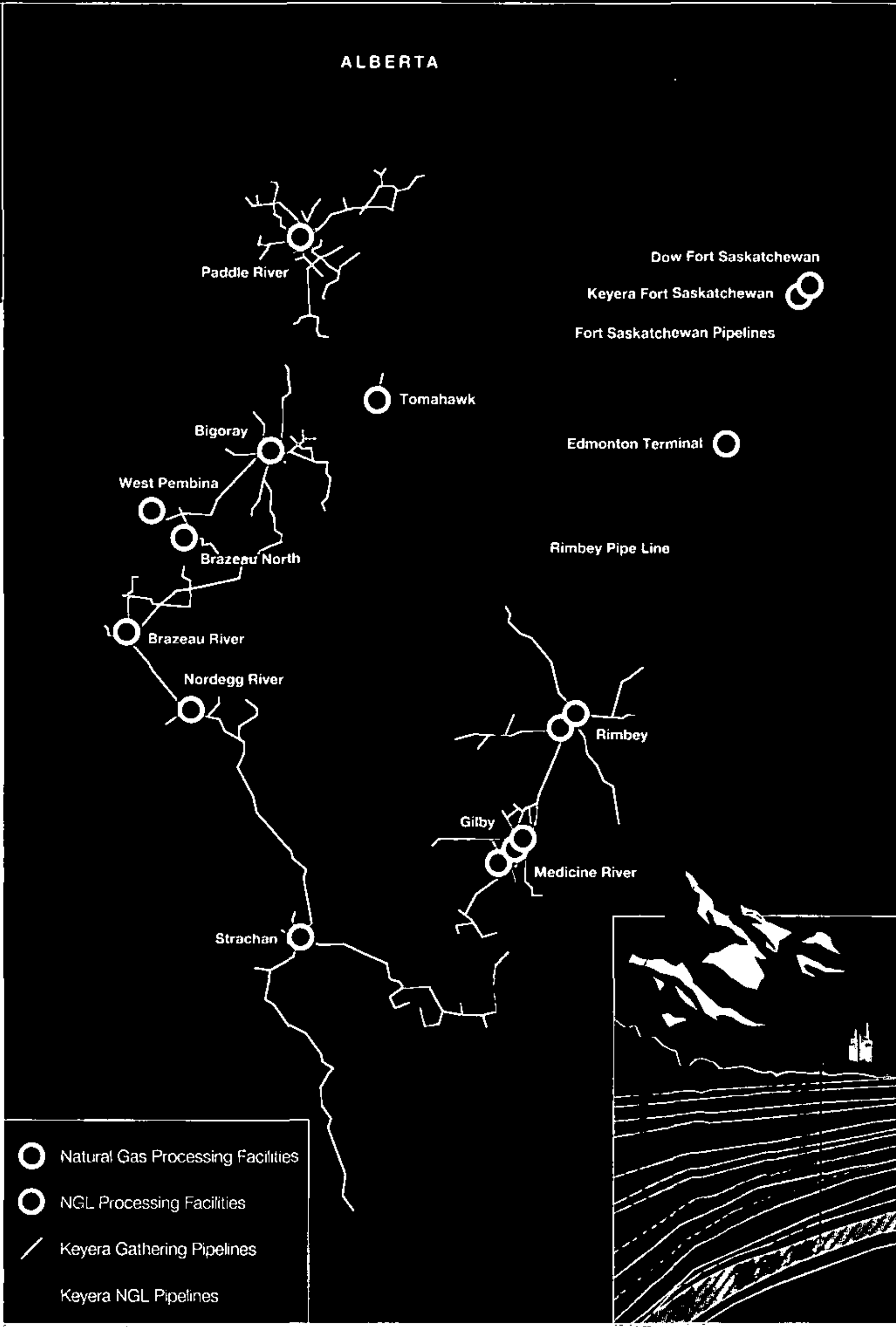
Increased bitumen production in Alberta has given rise to increased condensate demand in the province. Because demand for diluent has outstripped local supply, condensate is now being imported.

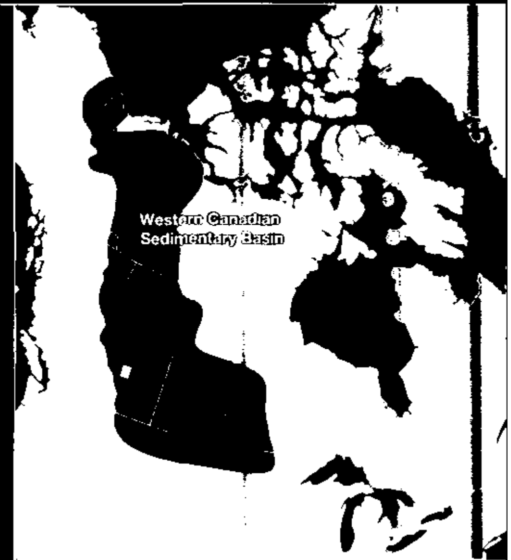
To accommodate additional imported volumes, in 2006 we expanded our Edmonton rail terminal by 50%. With room to simultaneously offload eight rail cars, the $7 million expansion now gives us the ability to import up to 10,000 barrels per day of condensate from U.S. markets and offload the product at our Edmonton terminal. Once offloaded, the condensate moves through the Edmonton terminal for delivery to end-use customers in the area. The new rail offload facility generates additional fee-for-service revenues when used by third parties.

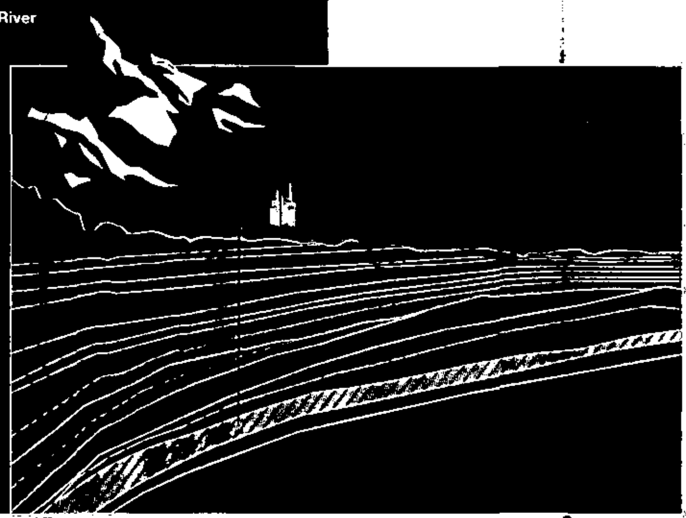


With room to simultaneously offload eight rail cars, we can import up to 10,000 barrels per day of condensate to serve Alberta's growing oil sands sector.

Gathering Pipelines and Processing Plants







Cross Section Illustration: *Keyera's facilities are located on the western side of the Western Canadian Sedimentary Basin where drilling activity remains strong. This region is relatively less explored. It has significant geological potential, and there are significantly more gas-prone zones. Deeper zones often contain larger reserves and may also contain hydrogen sulphide, carbon dioxide, and natural gas liquids, which require specialized processing to remove. Keyera's plants are expected to operate for many years, benefiting from ongoing producer activity.*

Gathering and Processing

A key North American supply basin

We believe that the Western Canadian Sedimentary Basin will continue to be a key source of North American natural gas supply for many years to come. The second largest basin in North America, with production sufficient to satisfy one quarter of current continental demand, it has large undeveloped, geologically prospective lands, an active exploration and production sector, and significant export pipeline infrastructure to transport natural gas from western Canada to downstream markets.

Fuelled by positive long-term industry fundamentals, western Canada has seen record drilling over the last few years. Much of this growth has occurred on the western side of the basin where the geology is attractive and significant reserves remain untapped. Advances in drilling and seismic technology combined with higher natural gas prices have encouraged producers to target deeper gas prone zones.

KEYERA'S FACILITIES ARE SITUATED IN HIGHLY PROSPECTIVE PRODUCTION REGIONS

Keyera's gathering and processing facilities are strategically located in the west central and foothills regions of the basin. These regions are characterized by deeper geology and larger natural gas reserves, and raw gas typically contains hydrogen sulphide, carbon dioxide, and natural gas liquids, which require significant processing to remove.

OUR FACILITIES ARE LARGE AND VERSATILE

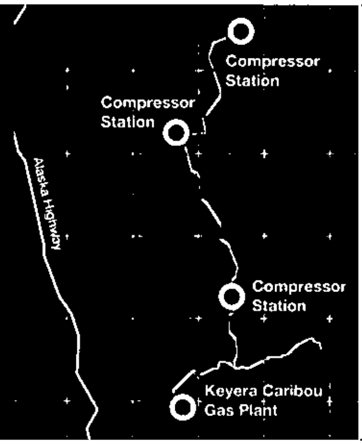
Our facilities are well-positioned to benefit from continued drilling activity in these areas. Our gas plants are large with broad capture areas and high barriers to entry, making them franchise facilities in the areas where they are located. Our plants are versatile and able to process both sweet and sour gas and extract natural gas liquids, which allows producers to maximize value from the raw natural gas they deliver. Many of our facilities have available unutilized capacity and are able to accommodate additional throughput from increased producer activity.

GROWTH PROJECTS POSITION FACILITIES FOR INCREASED PRODUCER ACTIVITY

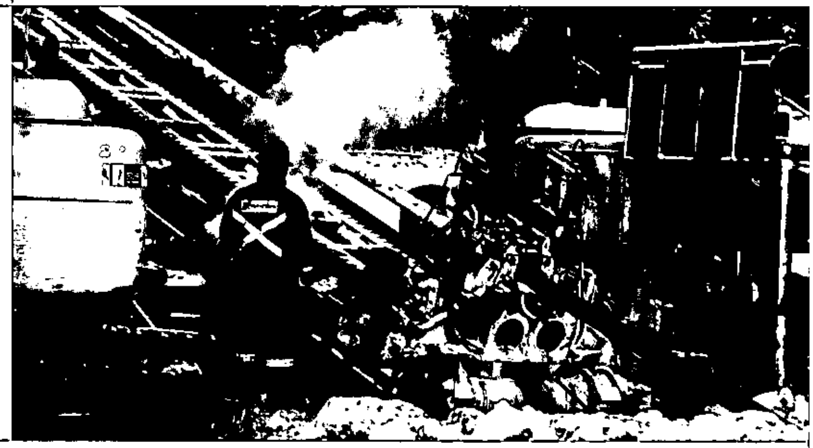
Producer activity and increased demand for gathering and processing services are generating numerous growth opportunities for Keyera. In 2006, we invested over $42 million in projects and acquisitions that supported producer initiatives and added value to unitholders. These projects will accommodate new growth in the areas where our facilities are located and position other assets for anticipated growth.

Major initiatives undertaken include the construction of two new gathering pipelines to our Caribou and Gilby gas plants, an expansion of our Caribou gas plant, the refurbishment of the sulphur extraction portion of our Strachan gas plant, and compression and optimization projects at a number of our facilities.

Caribou area, northeastern British Columbia.



Bottom Right: The Caribou North Gas Gathering System crosses two major river gorges with extremely steep banks. To overcome this challenge, holes were drilled simultaneously (photo at right) from the banks on either side of the river to connect in the middle, more than 100 metres beneath the river.



Expansion at Caribou North supports producer activity

Since acquiring the Caribou gas plant in 2004, Keyera has worked diligently to expand the capture area of the plant and support drilling activity in this remote area of northeastern British Columbia. Throughput at the plant has risen steadily as producers continue to discover and tie-in new gas for processing.

In 2006, Keyera invested $20 million to build the Caribou North Gas Gathering System to capture gas discovered in the area north of the plant. These discoveries were lacking the necessary pipeline infrastructure to transport gas for processing and delivery to sales markets. Our new 48-kilometre sour natural gas gathering pipeline delivers raw gas to Caribou for processing and opens a new 1,000 square kilometre exploration area for producers. To accommodate additional production, we also expanded the Caribou gas plant by 63% and now have a processing capacity of 65 million cubic feet per day.

The pipeline construction was a challenging project as its route crossed some very rugged terrain and involved two major river crossings. Our in-house engineering and project management expertise were essential in ensuring the project was completed on time and on budget.

With Keyera providing the needed infrastructure, producers are directing their attention and resources to exploring this new area, and the results to date have been encouraging. Two additional compressor stations have been tied-in to the pipeline and drilling activity is ongoing. At year-end, plant throughput at Caribou was averaging 51 million cubic feet per day, meaning that 44% of the expanded capacity is already being utilized.

"It's been a win-win situation. Keyera constructed the needed infrastructure in this area, allowing us to focus on finding more natural gas."

Kel Johnston
President and CEO
Alberta Clipper Energy Inc.

Our business interests are aligned with those of our customers. We work hard to build long-term relationships through great service and specialized industry knowledge.

Adding compression creates win-win situation

As a service provider to oil and gas producers, we are continually looking for opportunities to improve our service offering. With our extensive gathering systems and centralized processing facilities, a key focus is to develop projects that benefit both Keyera and our producing customers. A great example of this is at our Rimbey gas plant, where we recently implemented a compression project that created the type of win-win situation we strive to achieve.

During 2006, Keyera began working with several producers to enhance the productivity of wells that were operating at less than optimum pressure levels. Keyera agreed to invest $5 million to install compression facilities at the inlet of the Rimbey plant. This new compressor allows the operating pressure on the Gull Lake pipeline to be lowered by 50%.

This project has benefited both Keyera and our customers. The lower pipeline pressure extends the productive life of the wells, allowing our customers to continue to deliver volumes to the Rimbey gas plant via the Gull Lake pipeline. The use of centralized compression is also an efficient use of infrastructure, providing a more favourable operating environment for all producers. Keyera receives additional revenue from the compression service it now provides and will also benefit from increased plant throughput over the long term.

Gas processing requires high operating pressures and, to deliver raw gas into the plant, gas gathering systems must also operate at these high pressures. As a result, raw gas leaving the wellhead often requires compression to boost the pressure to the appropriate level.

Logistics

Logistics expertise a key to Keyera's marketing success

A key factor in our success is the integration of Keyera's three business segments: Gathering and Processing, NGL Infrastructure, and Marketing. This integration is particularly beneficial to our marketing group, who utilize Keyera's NGL processing, storage, and transportation infrastructure to source NGL supply and deliver specification products to customers across North America. To be successful in our NGL marketing and crude oil midstream activities, strategically located infrastructure and experienced people are essential. Keyera has both.

Keyera's professional logistics personnel manage the operational aspects of our marketing business in Calgary and at each of our rail, truck and pipeline terminals. Our Calgary personnel work with the railways to ensure that railcars are available for loading at our 13 rail and truck terminals in western Canada and delivered to end-use markets as scheduled. At each loading facility, our on-site personnel work to schedule and load each railcar and truck properly and safely for shipment. At our Edmonton terminal, pipeline operations personnel facilitate the delivery of propane, butane, and condensate to major refineries and petrochemical plants and to pipeline systems for delivery to markets throughout Alberta and beyond.

In 2006, Keyera's Edmonton terminal was presented with a Canadian Pacific Railway 2005 Chemical Shipper Safety Award. This award was in recognition of our success in shipping more than 4,000 railcars containing liquefied petroleum gases with no releases of gas or overloading of cars.

Our ability to deliver products into key end-use markets safely and efficiently represents a key competitive advantage for Keyera.

Keyera's logistics personnel in Calgary, and at facilities such as the Rimbey gas plant (photo above), play an essential role in the success of our NGL marketing activities.

Our ability to deliver NGL products into key end-use markets safely and efficiently is a key competitive advantage.

Marketing

The combination of marketing expertise, geographic and customer diversity, and strategically located infrastructure assets creates a significant competitive advantage.

NGL marketing and crude oil midstream activities a natural fit with infrastructure assets

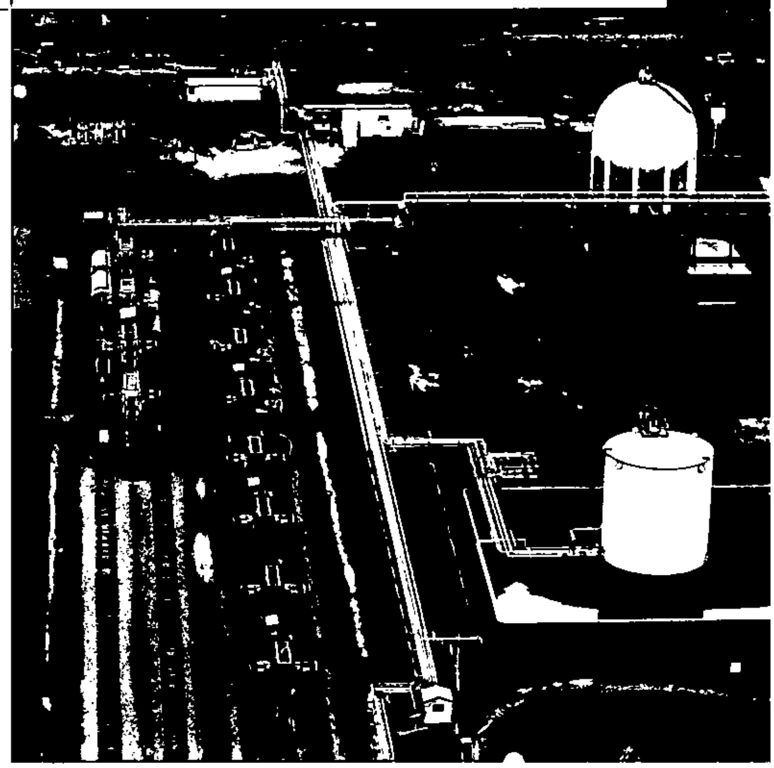
Keyera's marketing and crude oil midstream activities are a natural extension of our other two business lines. Our team of marketing professionals utilize the assets of our Gathering and Processing and NGL Infrastructure businesses to source and deliver products and services to customers across North America.

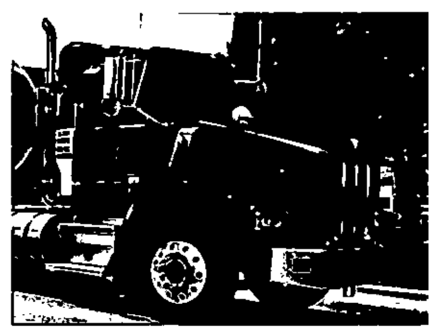
In our NGL marketing business, we purchase NGLs recovered from raw gas, often from gas processed at our own gas plants, for resale to customers across North America. Where product is purchased as NGL mix, we use one of our four NGL processing facilities to separate the NGL mix into products such as propane, butane, and condensate. Our marketers can also utilize Keyera's storage facilities at Fort Saskatchewan to store propane, butane, and condensate to meet future seasonal demand.

We expanded our NGL marketing business in 2006 through the acquisition of three propane distribution terminals in the United States. These assets allowed us to expand our wholesale customer base and diversify the geographic markets we serve.

Our crude oil midstream business continued to grow in 2006, benefitting from additional field facilities and the success of our joint venture with Pembina Pipeline Corporation. In 2006, we expanded the scope of this joint venture and, in December, commissioned a second crude oil midstream facility.

The combination of marketing expertise, strategically located processing and logistics infrastructure, a diversity of geographic markets, and a broad customer base creates a significant competitive advantage. This has allowed Keyera to develop one of the largest NGL marketing businesses in western Canada.



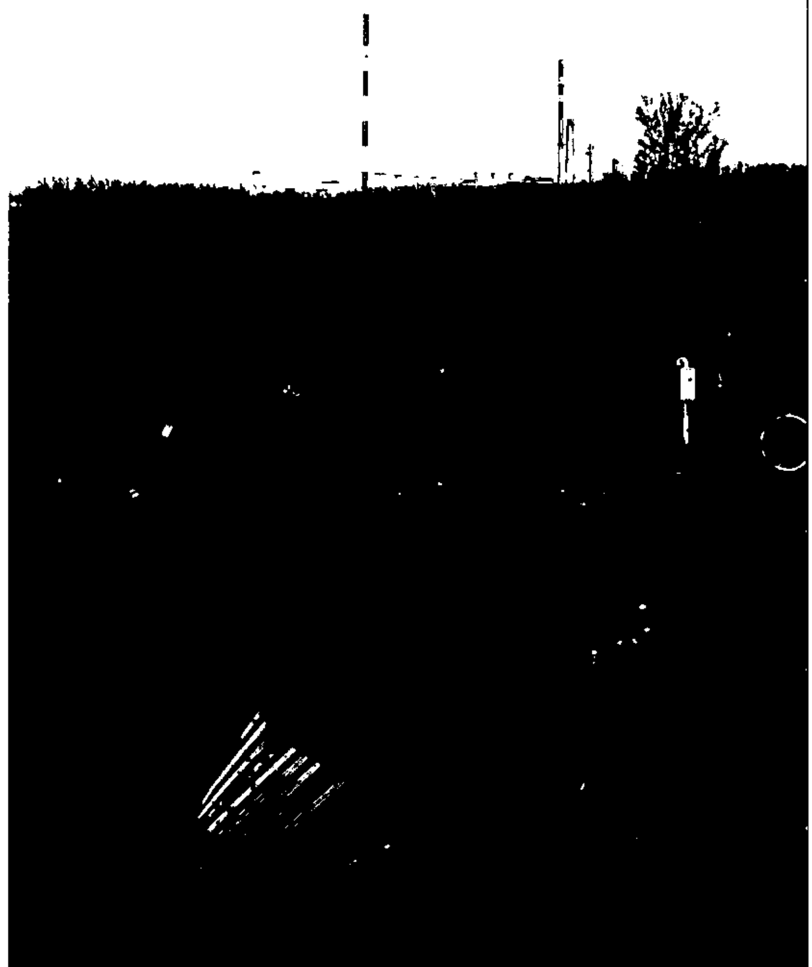


"We like working with the people at Keyera. They know the meaning of customer service."

George L. Koloroutis
Vice President
Ferrell North America

Corporate Responsibility

A commitment to our employees, the public, and the environment



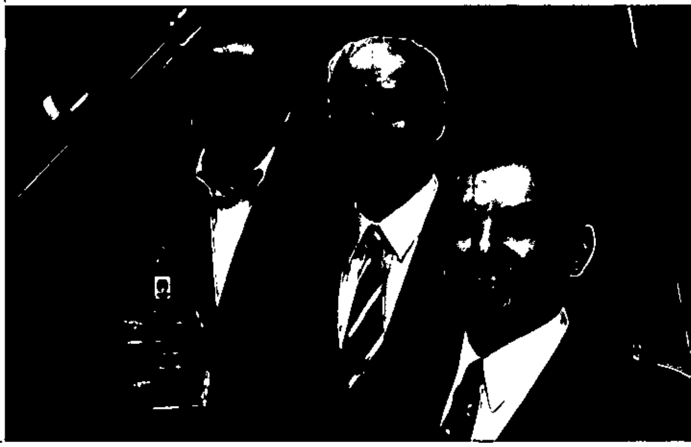
Economic growth, environmental protection, and social responsibility are all essential to the success of Keyera's corporate strategy. We conduct our business ethically, safely, and responsibly, which benefits employees, the public, and our unitholders.

COMMITTED TO HEALTH, SAFETY AND THE ENVIRONMENT

Our environmental programs focus on prevention of environmental impacts and we continually monitor and evaluate our operating procedures to minimize the potential for environmental and safety incidents.

Keyera strives to achieve an injury free workplace and has actively participated in Alberta Human Resources and Employment's Partnerships in Health and Safety Program since the program's inception in 1989. In 2006, Keyera successfully completed its latest external audit and our Certificate of Recognition (COR) has been renewed for another three years. We continue to make safety a key priority and embrace this commitment at all levels of our organization.

As important as financial and operating results are, nothing is more important than the safety of our people.



Keyera's innovative Capability Management and Development System allows us to develop highly trained employees to meet the demands of today's work environment.

Above: STARS provides safe, rapid, highly-specialized emergency medical air transport services for the critically ill and injured as well as outreach education programs to both rural and urban emergency service personnel.

Top: (Left to Right) Brian Lupul, Lakeland College; Gene Campbell and Bob Morrish, Keyera Energy, accepting the Conference Board of Canada Award for Excellence in Workplace Literacy.

COMPETENT AND EXPERIENCED WORKFORCE

We believe the most effective way to promote safe, efficient, and reliable operations is through a competent and experienced workforce. A key initiative in this regard was the creation of our innovative Capability Management and Development System (CMDS), which supports the assessment and enhancement of the skills our industry requires. The system enables Keyera to recruit, train, and internally develop knowledgeable and competent employees. This ability is crucial in today's work environment.

In December 2006, The Conference Board of Canada gave Keyera its Award for Excellence in Workplace Literacy, recognizing CMDS as an innovative and effective workplace literacy program.

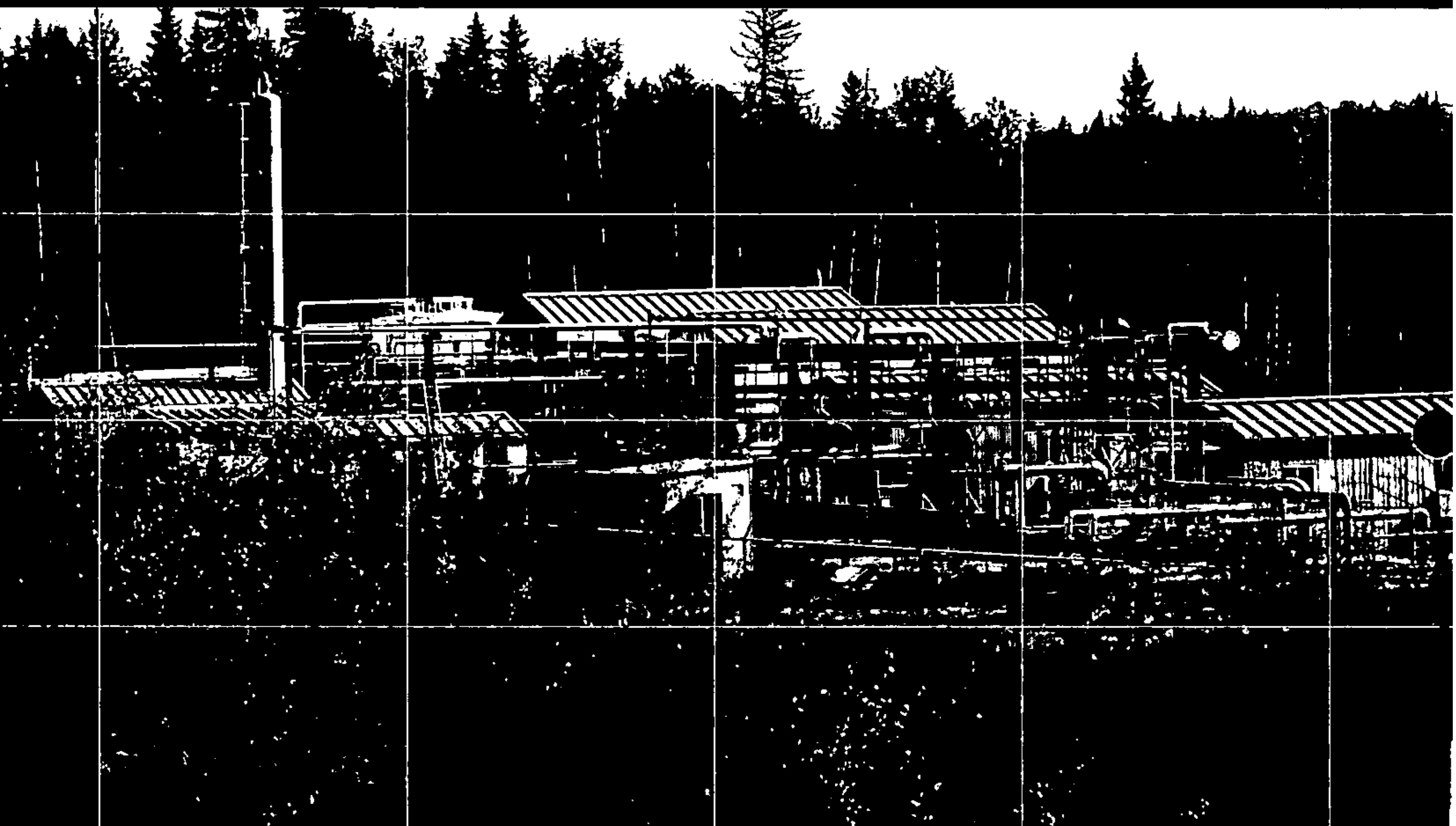
Keyera shares the CMDS system with more than 20 energy companies across Canada, providing industry training to over 3,000 workers. As well, it forms the basis of a new two-year diploma program at Lakeland College in Vermilion, the first of its kind in Alberta where credits are earned outside a post-secondary classroom.

PARTNERING WITH OUR COMMUNITIES

Keyera supports the communities where we live and operate through modest financial contributions and by providing employee time to major campaigns and two paid volunteer days annually to support community activities.

Because the majority of Keyera's employees are located at field facilities in Alberta and northeast British Columbia, in 2005 we entered into a significant five-year partnership with the Alberta Shock Trauma Air Rescue Society (STARS). STARS delivers timely emergency medical care to over 90% of Alberta's population and many British Columbia communities adjacent to the Alberta border. This partnership reflects our dedication to the welfare of our people and the communities where they live.

Management's Discussion and Analysis



Our strong balance sheet provides financial stability, allowing us to pursue internal growth prospects while supporting stable cash distributions.

Conservative capital structure • Financial stability • Low risk profile • Growing business • Stable distributions

Management's Discussion and Analysis

The following management's discussion and analysis ("MD&A") was prepared as of February 27, 2007 and is a review of the results of operations and the liquidity and capital resources of Keyera Facilities Income Fund (the "Fund" or "Keyera"). It should be read in conjunction with the accompanying audited consolidated financial statements of the Fund for the year ended December 31, 2006 and the notes thereto as well as the consolidated financial statements of the Fund for the year ended December 31, 2005 and the related management's discussion and analysis. Additional information related to the Fund, including the Fund's Annual Information Form, is filed on SEDAR at www.sedar.com.

NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This discussion and analysis refers to certain financial measures that are not determined in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). These measures do not have standardized meanings and may not be comparable to similar measures presented by other trusts or corporations. Measures such as operating margin (operating revenues minus operating expenses), EBITDA (earnings before interest, taxes depreciation and amortization) and distributable cash flow (net income adjusted for items not affecting cash less maintenance capital expenditures, expenditures related to asset retirement or site reclamation and the distributable cashflow attributable to any non-controlling interest) are not standard measures under GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Management believes that these supplemental measures facilitate the understanding of the Fund's results of operations and financial position. Investors are cautioned, however, that these measures should not be construed as an alternative to net earnings determined in accordance with GAAP as an indication of the Fund's performance.

FORWARD LOOKING STATEMENTS

Certain statements contained in this MD&A and accompanying documents contain forward-looking statements. These statements relate to future events or the Fund's future performance. Such statements are predictions only and actual events or results may differ materially. The use of words such as "anticipate," "continue", "estimate", "expect", "may", "will", "project", "should," "plan," "intend," "believe," and similar expressions, including the negatives thereof, is intended to identify forward looking statements. All statements other than statements of historical fact contained in this document are forward looking statements, including, without limitation, statements regarding: the future financial position of Keyera; business strategy and plans of management; anticipated growth and proposed activities; budgets, including future capital, operating or other expenditures and projected costs; estimated utilization rates; objectives of or involving Keyera; impact of commodity prices; treatment of Keyera under governmental regulatory regimes; the existence, operation and strategy of the risk management program, including the approximate and maximum amount of forward sales and hedging to be employed; and expectations regarding Keyera's ability to raise capital and to add to its assets through acquisitions or internal growth opportunities.

The forward looking statements reflect management's current beliefs and assumptions with respect to such things as the outlook for general economic trends, industry trends, commodity prices, capital markets, and the governmental, regulatory and legal environment. Management believes that its assumptions and analysis are reasonable and that the expectations reflected in the forward looking statements contained herein are also reasonable. However, Keyera cannot assure readers that these expectations will prove to be correct.

All forward looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results, events, levels of activity and achievements to differ materially from those anticipated in the forward looking statements. Such factors include but are not limited to: general economic, market and business conditions; operational matters, including potential hazards inherent in our operations; risks arising from co-ownership of facilities; activities of other facility owners; competitive action by other companies; activities of producers and other customers and overall industry activity levels; changes in gas composition; fluctuations in commodity prices and supply/demand trends; processing and marketing margins; effects of weather conditions; fluctuations in interest rates and foreign currency exchange rates; changes in operating and capital costs, including fluctuations in input costs; actions by governmental authorities; decisions or approvals of administrative tribunals; changes in environmental and other regulations; reliance on key personnel; competition for, among other things, capital, acquisition opportunities and skilled personnel; changes in tax laws relating to income trusts, including the effects that such changes may have on Unitholders, and in particular any differential effects relating to Unitholder's country of residence; and other factors, many of which are beyond the control of Keyera, some of which are discussed in this MD&A and in Keyera's 2007 Annual Information Form filed on SEDAR.

In addition, this MD&A and accompanying documents may contain forward-looking statements attributed to third party sources. For example, the discussion on proposed changes in trust tax legislation is based solely on the general information found in the background paper issued by the Department of Finance at the time of the October 31, 2006 announcement by Minister Flaherty, the proposed "normal growth" guidelines issued by the Department of Finance on December 15, 2006, and the draft amendments to the Tax Act released on December 21, 2006 (collectively the "October 31 Proposals"). No assurance can be given that any final legislation implementing the proposed tax changes will be consistent with the October 31 Proposals or that Canadian federal income tax law respecting income trusts and other flow-through entities will not be further changed in a manner which adversely affects Keyera and its Unitholders. To the extent that proposed or other changes are implemented, such changes could result in the income tax considerations described in this MD&A being materially different.

Readers are cautioned that they should not unduly rely on the forward looking statements included in this MD&A and accompanying documents. Further, readers are cautioned that the forward looking statements contained herein speak only as of the date of this MD&A and Keyera does not undertake any obligation to publicly update or to revise any of the forward looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable laws.

All forward looking statements contained in this MD&A and accompanying documents are expressly qualified by this cautionary statement. Further information about the factors affecting forward looking statements and management's assumptions and analysis thereof, is available in filings made by Keyera with Canadian provincial securities commissions available on www.sedar.com.

INTRODUCTION

The statement of earnings contained in the audited consolidated financial statements includes the results of operations of the Fund, Keyera Energy Partnership ("the Partnership"), Keyera Energy Facilities Limited ("KEFL"), Keyera Energy Ltd. ("KEL"), Keyera Energy Management Ltd. ("KEML"), Keyera Energy Inc. ("KEI") and Rimbey Pipe Line Co. Ltd. ("Rimbey Pipe Line") for the twelve months ended December 31, 2006. The Fund and its subsidiaries are collectively referred to as "Keyera". The information for the comparative twelve months ended December 31, 2005 includes the results of operations of the Fund, the Partnership, KEFL, KEL, KEML, KEI, EnerPro Midstream Company ("EnerPro") and Rimbey Pipe Line for the twelve months ended December 31, 2005. A diagram of Keyera's organizational structure and descriptions of the Fund and its subsidiaries can be found in the Fund's 2007 Annual Information Form which is available at www.sedar.com.

BUSINESS ENVIRONMENT

Canada experienced another active year of oil and gas drilling in 2006, with 23,441 wells drilled during the year. Although drilling levels overall were 6% lower than last year, in the foothills front and British Columbia regions, where most of Keyera's facilities are located, the number of wells drilled increased by 2% compared to last year, setting new records for these areas.

Low natural gas prices in 2006 affected some producer drilling programs during the year, particularly in the central and eastern side of the Western Canadian Sedimentary Basin ("WCSB"). In the central Alberta region, where Keyera has operations, drilling of natural gas wells decreased 23% compared to 2005, largely the result of a curtailment of shallow gas and coal bed methane drilling. The average depth of wells drilled in the central Alberta region increased by 10% in 2006, as producers continued to target deeper reservoirs. Keyera was not significantly affected in 2006 by the drilling slowdown in this area, as gas from shallow sweet wells does not contribute significantly to Keyera's cash flow.

Over the long-term, natural gas fundamentals are expected to support an active drilling program in the WCSB. This is particularly true on the western side of the basin. This area is relatively under-developed, has more gas prone zones at deeper depths and often has larger reserves containing hydrogen sulphide and natural gas liquids ("NGLs"). The majority of Keyera's facilities are able to process both sweet and sour gas and extract NGLs from the raw gas stream, making them well-suited to process gas from this region.

The high levels of activity around Keyera's facilities over the last several years have resulted in a material amount of natural gas being discovered but, for a variety of reasons, production to date from these discoveries has been limited. Producers in several areas have initiated drilling programs and production from these sources is expected to come on stream in 2007.

The expected increases in bitumen and heavy oil production from northeastern Alberta over the next 10 to 20 years are expected to increase the demand for condensate, for use as diluent in heavy oil transportation, as well as generate opportunities to provide storage and logistics services in the Fort Saskatchewan area. Keyera's facilities in Edmonton and Fort Saskatchewan experienced increased demand for these products and services during 2006, and are well positioned to provide additional services over the longer term as the oil sands sector evolves.

On October 31, 2006, the Government of Canada announced a new tax on a portion of the distributions of publicly-traded Canadian income trusts and limited partnerships. Assuming legislation is passed to enact this new tax, Keyera, as an existing income trust, will be subject to the new tax as of January 2011. Details of the Government's proposed changes can be found in the Government's website at http://www.fin.gc.ca/news06/06-061e.html.

According to the announcement, effective January 1, 2011 a tax of 31.5% will be payable by Keyera on the portion of its distributions that is ordinary taxable income. For a Canadian resident taxpayer, this portion of Keyera's distributions will be treated as dividend income for tax purposes. The announcement also indicates that there will be no change in taxation of Keyera's distributions that are considered to be a return of capital or dividend income.

If enacted as proposed, the taxation of Keyera commencing in 2011 will depend upon the composition of its distributions. The composition of the distributions will vary depending upon levels of profitability, capital expenditures and other factors.

As at January 1, 2006, Keyera had over $375 million of unutilized tax pools and deductions, consisting mostly of class 41 undepreciated capital costs, available for deduction by the Fund's subsidiaries. Keyera's practice has been to minimize taxes payable by the Fund and its subsidiaries. Keyera is reviewing the implications of the government's announcement and, should the proposed tax changes become law, Keyera will continue to adopt strategies that are intended to enhance long-term value.

PRODUCTIVE CAPACITY

Keyera's Gathering and Processing segment has interests in 16 gas processing plants in Western Canada with 1,663 million cubic feet per day ("mmcf/d") of licensed gross raw gas processing capacity (1,328 mmcf/d net), of which an average of 819 mmcf/d was utilized in 2006. Actual available raw gas processing capacity can be less than the licensed capacity, particularly if current gas composition or plant operating conditions are significantly different than the original plant design. Each plant has a number of functional units, each of which performs one or more operations, such as NGL recovery, gas treating and sulphur recovery. The constraint on actual available capacity depends on the capacity of each functional unit at each plant. Additional information on the capacities and constraints for Keyera's plants is provided in Keyera's 2007 Annual Information Form, which is available on SEDAR.

Associated with these gas plants, Keyera owns interests in over 2,500 kilometres of four to twelve inch diameter raw gas gathering pipelines that deliver raw gas to the gas plants for processing.

Keyera also owns an integrated NGL infrastructure consisting of pipelines, processing, storage, and rail and truck loading facilities in Edmonton and Fort Saskatchewan, Alberta. Keyera has a total net NGL processing capacity of 65,170 bbls/d and net storage capacity of 7 million barrels.

Several of Keyera's sour gas plants rely on acid gas injection to dispose of the hydrogen sulphide and waste-products removed during processing. Acid gas injection involves the injection and sequestration of carbon dioxide and hydrogen sulphide into depleted underground reservoirs. The sustainability of this particular process is dependent upon the availability of suitable reservoirs. Keyera routinely monitors its existing reservoirs at the Brazeau River, West Pembina, Bigoray, Caribou and Paddle River gas plants to determine whether sufficient capacity remains available. If capacity were to become unavailable, alternate processes would be required or the capacity of the plant would be reduced.

Keyera has comprehensive inspection, monitoring and maintenance programs in place. The objectives of these programs are to keep the facilities in good working order and to maintain their ability to operate reliably for many years. In 2006 Keyera and its partners spent $31.0 million to maintain the productive capacity of its facilities, $26.5 million of which was expensed and $4.5 million capitalized. Keyera's net share of these expenditures was $22.5 million, $19.5 million of which was expensed and $3.0 million of which was capitalized. In 2007, Keyera's net share of expenditures related to the maintenance of productive capacity (both capitalized and expensed) is expected to be between $27 million and $33 million. A large portion of these maintenance costs will be recovered through the fee structure at each plant in 2007. With ongoing maintenance and repair, it is anticipated that Keyera's plants and facilities can continue to operate safely for decades to come.

RESULTS OF OPERATIONS

Keyera's midstream activities are conducted through three business segments. The Gathering and Processing segment provides natural gas gathering and processing services to producers. The NGL Infrastructure segment provides NGL processing, transportation and storage services to producers, marketers (including Keyera) and others. The services in both these segments are provided on a fee-for-service basis. The Marketing segment is focused on the marketing of by-products recovered from the processing of raw gas, primarily NGLs, and crude oil midstream activities. A more complete description of Keyera's businesses by segment can be found in the Fund's 2007 Annual Information Form, which is available at www.sedar.com.

Consolidated net earnings for 2006 were $68.1 million, an increase of $7.4 million from 2005. This increase was primarily attributable to the strong contribution of the storage business in the NGL Infrastructure segment, lower long-term incentive plan costs in the general and administrative expenses and the recovery of future income taxes in the second quarter of 2006. Partially offsetting this were lower operating margins experienced in the third and fourth quarters of 2006 in the Marketing segment, primarily attributable to weakening product prices.

Consolidated net earnings for the fourth quarter of 2006 were $14.9 million, down $0.6 million from the same period in 2005. The strong operating margin earned from the Gathering and Processing and NGL Infrastructure segments largely mitigated the weaker results seen in the Marketing segment. Significantly lower general and administrative costs partially offset by higher interest, depreciation and income taxes also mitigated the effect of the lower Marketing results.

Gathering and Processing

Gathering and Processing revenue for 2006 was $166.7 million, an increase of $27.5 million, or 20%, compared to the previous year. The increase was due primarily to higher throughput in the West Central Region; increased sour gas volumes, which attract a higher processing fee, at the Brazeau River gas plant; the recovery of expenses incurred during the Chinchaga and Strachan gas plant maintenance turnarounds; and increased ownership in the Strachan gas plant for the full year.

In the fourth quarter of 2006, Gathering and Processing revenue was $43.6 million, an increase of $6.3 million, or 17%, compared to the same period in 2005. The increase was due primarily to higher throughput at the Brazeau River, Caribou and Gilby plants. At Caribou and Gilby the increase in volumes was attributable to the completion of new gathering systems earlier in the year and the plant expansion undertaken at Caribou. The Brazeau River plant also saw higher acid gas injection volumes and higher fees from firm commitment contracts and to recover maintenance costs incurred earlier in the year. Also contributing to growth was the incremental ownership interest in the Strachan gas plant.

Gathering and Processing operating expenses were $96.6 million, an increase of $29.1 million, or 43%, compared to previous year. Approximately $21.1 million of this increase was attributable to the turnarounds conducted at the Caribou, Chinchaga and Strachan gas plants and the substantial amount of additional maintenance work to refurbish the sulphur handling facilities at the Strachan gas plant. This work positioned the plant to provide increased sour gas processing capability in a safe, reliable and environmentally responsible manner. The remainder of the increase was due to increased operating costs resulting from the higher throughput in the West Central region and compressor repairs at the Brazeau River plant.

In the fourth quarter of 2006, Gathering and Processing operating expenses were $22.3 million, an increase of $2.0 million compared to the same period in 2005. The increase was due to higher volumes and activity levels at the Brazeau River and Caribou gas plants.

Much of the revenue from the Gathering and Processing segment is generated on a cost-of-service basis. On a percentage basis, the increase in operating costs was higher than the increase in revenue, primarily due to timing differences that occur as a result of the cost-of-service fee structure. At the Strachan gas plant, where the most significant maintenance and turnaround activities occurred, costs are recovered over a four year period. At the Caribou plant, many of the contractual arrangements are on a fixed-fee basis where certain costs incurred in the year are not directly recoverable.

Average gross processing throughput in 2006 was 819 million cubic feet per day, 4% higher than 2005. Fourth quarter throughput of 808 million cubic feet per day was up 1% from the same period last year.

Gathering and Processing – West Central Region

The West Central Region continued to deliver strong performance in 2006, increasing cash flows and executing a number of growth initiatives. Annual raw gas throughput for the region increased 5% compared to 2005. Fourth quarter throughput in the region was virtually unchanged from the same period a year ago.

In the Rimbey area, a number of initiatives were completed in 2006 which provide Keyera with greater control over its gathering pipelines and enhance its ability to deliver raw gas to the Rimbey gas plant. For example, Keyera acquired additional ownership interests in the Medicine River and Gull Lake pipelines, bringing its ownership to 87% and 100% respectively. These pipelines capture raw gas from areas currently experiencing active drilling programs for delivery to the Rimbey gas plant.

Inlet compression was added at the Rimbey gas plant during the year to accommodate additional volumes. These projects enable the pipelines to operate at lower operating pressures, which allows more low pressure gas wells to deliver gas to the plant.

In April 2006, Keyera completed the construction of the 20-kilometre Aurora pipeline. Upon completion, the pipeline immediately began delivering incremental raw gas to the Gilby gas plant from an active area west of the plant.

Producer activity in the area near Keyera's Brazeau North, West Pembina and Bigoray plants progressed at high levels in 2006. Piping and compression modifications were completed during the year at the Brazeau North and West Pembina gas plants, which provided increased inlet capabilities and resulted in an incremental 5 million cubic feet per day of raw gas throughput at those facilities. In the fourth quarter, work continued on the conversion of an out-of-service sales pipeline into an additional gathering pipeline for the Bigoray gas plant.

In 2007, maintenance turnarounds will be completed at the Rimbey, Bigoray, Brazeau North and Medicine River gas plants. With the exception of the Rimbey gas plant, where maintenance costs are recovered over a four year period, the majority of these costs will be recovered in 2007.

Gathering and Processing – Foothills Region

In the Foothills region, drilling activity near Keyera's facilities continued during the year and 2006 throughput for the region was up 4% over 2005. Fourth quarter throughput was also up 4% from the same quarter in 2005.

The Strachan gas plant underwent extensive work during 2006 in order to prepare for incremental sour gas volumes over the next several years. During the second quarter, Strachan's scheduled maintenance shutdown was completed, with necessary inspections, routine repairs and numerous modifications being performed. The "A" sulphur plant was also refurbished to enable both the "A" and "B" sulphur plants to process sour gas volumes from the Tay River discovery south of the plant. Pipeline modifications began in the fourth quarter to accommodate the water associated with the increased raw gas volumes. Keyera expects these modifications to be completed in the first quarter of 2007. In February 2007, deliveries of gas from the Tay River discovery increased to rates exceeding 50 million cubic feet per day. At these throughput levels, Strachan's sulphur handling facilities were operating near their capacity.

The 48-kilometre Caribou North Gas Gathering System was completed in 2006, extending the capture area of the Caribou gas plant to the north. The pipeline opened a 1,000 square kilometer area which lacked gathering and processing infrastructure. To accommodate expected incremental volumes from the area, the Caribou gas plant was expanded in June from 40 to 65 million cubic feet per day while the plant was off-line for its scheduled maintenance shutdown. Two producer-owned compressor sites were connected to the pipeline in the second half of the year. A third producer-owned compressor site began delivering new volumes into the gathering system in January 2007. Several producers currently have drilling programs underway along the pipeline.

In the Pembina area, activity continued during the year on the Nisku oil play and three producer-owned batteries became operational. Regulatory and operational issues at these batteries resulted in lower than expected volumes at the Brazeau River gas plant during the year. Volumes increased during the fourth quarter and this trend has continued through the first two months of 2007. As a result, the sour gas handling facilities at the Brazeau River gas plant have been operating at or near capacity. During the third and fourth quarters of 2006, a number of processing agreements were put in place which secure processing capacity for producers and processing revenues for Keyera.

The Chinchaga gas plant was off-line during the third quarter of 2006 to perform its scheduled maintenance turnaround. In 2007, the Brazeau River gas plant will undergo its scheduled maintenance turnaround and these costs will be fully recovered in 2007.

NGL Infrastructure

NGL Infrastructure revenue for 2006 was $39.9 million, an increase of $4.9 million, or 14%, compared to the previous year. The increase was primarily due to higher storage revenues at Keyera's Fort Saskatchewan facility, as well as a non-recurring adjustment of approximately $1 million earned upon the expiration of a long-term contract in the first quarter of 2006.

NGL Infrastructure operating expenses for 2006 were $24.0 million, a decrease of $0.3 million or 1% compared to 2005. Lower fuel gas and electricity costs throughout most of the year accounted for the decrease.

In the third quarter, Keyera completed construction of a 3.9 million barrel brine pond at the Fort Saskatchewan processing and storage facility. This brine pond enables a better utilization of the existing underground storage at Fort Saskatchewan and will allow Keyera to take advantage of the increasing long-term demand for condensate and butane storage. In anticipation of the completion of the brine pond, Keyera entered into multi-year storage contracts. These contracts, together with other shorter term arrangements, resulted in an increase in storage revenues in 2006.

Also, in the third quarter of 2006, Keyera completed the construction of an expansion to the rail rack facility at the Edmonton terminal. The expansion allows the offloading of up to 10,000 barrels per day of condensate, intended to supply the diluent market in Alberta.

In the fourth quarter of 2006, NGL Infrastructure results were up significantly from the same period in 2005. Operating margin for the fourth quarter of 2006 was $4.8 million, an increase of $2.4 million compared to last year. At the Fort Saskatchewan fractionation facility, lower fuel and electricity costs contributed to significantly lower operating expenses, while revenues showed a modest increase. The Edmonton terminal had an active fourth quarter, as propane was withdrawn from storage and delivered, via rail and truck, to markets throughout North America.

Marketing

Marketing revenue for 2006 was $1,162 million, an increase of $148.6 million compared to the previous year. Approximately $52.3 million of the increase was due to the growth of the crude oil midstream business that commenced operation in the fourth quarter of 2005. Also included in revenue was $7.0 million related to the settlement of and the change in fair value of financial contracts that were part of Keyera's risk management program. The remainder was primarily due to higher NGL volumes and prices compared to last year.

The tables below outline the composition of the revenues generated from Keyera's Marketing business and the changes in the fair value of the derivative financial contracts.

Composition of Marketing Revenue

(in thousands of dollars)	**2006**
Physical sales	1,154,853
Financial instruments	7,046
Marketing revenue	**1,161,899**

Changes in Fair Value of Energy Derivative Contracts

(in thousands of dollars)	
Fair value at December 31, 2005	(280)
Change in the fair value of contracts	6,835
Fair value of new contracts entered into in 2006	211
Realized gains	(6,555)
Fair value at December 31, 2006 [1]	**211**

[1] *The fair value of the financial contracts represents an estimate of the amount that Keyera would pay or receive if those contracts were closed on December 31, 2006.*

NGL sales volumes for 2006 averaged 52,200 barrels per day compared to 50,700 barrels per day in 2005, as all products experienced modest growth. In the fourth quarter of 2006, NGL sales volumes averaged 55,400 barrels per day compared to 55,000 barrels per day in the fourth quarter of 2005.

The cost of goods sold for 2006 was $1,102 million, an increase of $155.8 million compared to the previous year. The increase was due primarily to the inclusion of crude oil midstream costs and higher NGL sales volumes and supply costs compared to 2005. Also included in the cost of goods sold was $3.2 million related to inventory writedowns, $2.2 million in the third quarter and $1.0 million at year end. These writedowns were required as a result of the significant price drop in crude oil and product prices in the third and fourth quarters of 2006.

NGL product inventories of $53.9 million were $0.7 million higher than the previous year due to higher volumes partially offset by lower prices at year end. A significant portion of this inventory was sold in early 2007. Inventory has been valued at the lower of cost or net realizable value at December 31, 2006.

Propane demand followed normal season trends in 2006. Despite warmer than usual weather throughout most of North America during the fourth quarter, Keyera was able to utilize its infrastructure and marketing and logistics expertise to access niche markets where unseasonable weather created higher demand.

Demand for butane was relatively strong for the first three quarters of the year. Butane is required to support western Canadian crude oil production and for use in winter gasoline blending. During the fourth quarter, operational problems at a large industrial facility resulted in decreased demand and lower prices for butane in the Edmonton market. During this time, Keyera placed product into storage at its facilities in Fort Saskatchewan.

During the first half of 2006, condensate demand was strong as heavy oil producers continued to purchase condensate for use as diluent to enable heavy crude oil to flow in pipelines. Beginning in the third quarter, condensate demand and prices weakened significantly in part due to falling crude oil prices, an outage at a major heavy oil field in Alberta, and an increase in the supply of diluent in Alberta. This combination resulted in losses on the physical sale of condensate and a writedown of inventory values.

Marketing operating margins in the fourth quarter of 2006 were $11.8 million, down $8.7 million from the same period in 2005. Warm weather in the eastern U.S. contributed to lower propane prices, while butane and condensate markets also remained soft. As well, adjustments relating to the voidance of a butane cavern in the fourth quarter reduced margins by $0.8 million. However, by year end, the supply/demand fundamentals for propane, butane and condensate began improving and the market demand for these products is currently at more typical levels.

In the second quarter of 2006 Keyera acquired three propane terminals in the U.S. to expand its NGL marketing business in key propane markets. This acquisition allowed Keyera to vertically integrate its business, diversify its geographic markets and expand its wholesale customer base. During the last half of 2006, these terminals played a key role in delivering propane into the Pacific Northwest, which was experiencing unseasonably cold weather.

Keyera's crude oil midstream business continued to develop in 2006. Volumes delivered to field oil terminals remained steady and quality differentials were strong throughout the year, enabling the business to contribute approximately $8.5 million to operating margins. The midstream joint venture project that was initiated with Pembina Pipeline Corporation ("Pembina") at the Edmonton terminal in late 2005 contributed a significant portion of the operating margin in 2006. Another similar project was undertaken with Pembina in 2006 and construction of the required facilities was completed by year end. The new facilities were commissioned in early January 2007.

Non-operating expenses and other earnings

General and administrative expenses for 2006 were $18.9 million, down $6.3 million from the previous year. Long-term incentive plan costs were $7.6 million lower than in 2005, reflecting a decline in unit price and no change in distributions per unit. Excluding the effect of the long-term incentive plan, general and administrative expenses increased $1.3 million compared to the previous year. Severance costs and higher legal and consulting costs were primarily responsible for the increase. Severance costs were incurred in accordance with an employment agreement.

Interest expense, net of interest revenue, was $18.2 million for 2006, $1.9 million greater than in 2005. The increase was due to the higher short term borrowings used to fund capital projects, partially offset by a reduction in interest paid on lower convertible debenture balances.

Depreciation and amortization expense was $39.8 million for 2006, $3.0 million greater than the previous year. The increase was due to growth in the asset base resulting from the completion of several major construction projects during the past year.

Income tax recovery for 2006 was $2.7 million, compared to an expense of $6.6 million in the previous year. The reduction in tax expense was due to a decrease in future tax liabilities attributable to the lowering of statutory income tax rates and the recognition of the long-term incentive plan costs as a future tax asset. The plan costs became eligible for deduction from taxable income in future years when Keyera began purchasing units in the market for delivery under the plan. The deductibility of future unit purchase costs created a tax asset. Current income tax expense, primarily attributable to Rimbey Pipe Line, was $4.4 million, up slightly from the previous year.

On October 31, 2006 the federal government announced its intention to impose a new tax on distributions from existing public income trusts effective in 2011. Legislation to implement the proposed tax has been released for comment but has not been enacted, and the accounting guidance for future income taxes in flow-through entities has not been finalized. However, if the new legislation is put into effect, it is anticipated that the Fund's future income tax liability will increase significantly, with a corresponding decrease to net income in the period when the legislation is substantively enacted.

Critical Accounting Estimates

The Fund's consolidated financial statements have been prepared in accordance with GAAP. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the recorded amounts of certain assets, liabilities, revenues and expenses. Management reviews its assumptions and estimates regularly, but new information and changes in circumstances may result in actual results or revised estimates that differ materially from current estimates. The most significant estimates are those indicated below:

Estimation of Gathering and Processing and NGL Infrastructure revenues:

For each month, actual volumes processed and fees earned from the Gathering and Processing and NGL Infrastructure assets are not known at the month end. Accordingly, the financial statements contain an estimate of one month's revenue based upon a review of historic trends. This estimate is adjusted for events that are known to have a significant effect on the month's operations such as non-routine maintenance projects.

At December 31, 2006, operating revenues and accounts receivable for the Gathering and Processing and NGL Infrastructure segments contained an estimate of $19.5 million for December 2006 operations.

Estimation of Gathering and Processing and NGL Infrastructure operating expenses:

The period in which invoices are rendered for the supply of goods and services necessary for the operation of the Gathering and Processing and NGL Infrastructure assets is generally later than the period in which the goods or services were provided. Accordingly, the financial statements contain an estimate of one month's operating costs based upon a review of historical trends. This estimate is adjusted for events that are known to have a significant effect on the month's operations such as non-routine maintenance projects.

At December 31, 2006, operating expenses and accounts payable contained an estimate of $10.0 million for December 2006 operations.

Estimation of Gathering and Processing and NGL Infrastructure equalization adjustments:

Much of the revenue from the Gathering and Processing and NGL Infrastructure assets is generated on a cost-of-service basis. Under this method, the operating component of the fee is a pro rata share of the operating costs for the facility, calculated based upon total throughput. Users of each facility are charged a fee per unit based upon estimated costs and throughput, with an adjustment to actual throughput completed after the end of the year. Each quarter, throughput volumes and operating costs are reviewed to determine whether the estimated unit fee charged during the quarter properly reflects the actual volumes and costs, and the allocation of revenues and operating costs to other plant owners is also reviewed. Appropriate adjustments to revenue and operating expenses are recognized in the quarter and allocations to other owners are recorded.

For the Gathering and Processing and NGL Infrastructure segments, operating revenues and accounts receivable contained an equalization adjustment of $6.4 million at December 31, 2006. Operating expenses and accounts payable contained an estimate of $3.4 million.

Estimation of Marketing revenues:

The majority of the Marketing sales revenues are recorded based upon actual volumes and prices; however, in many cases actual product lifting volumes have not yet been confirmed and sales prices that are dependent on other variables are not yet known. Accordingly, the financial statements contain an estimate for these sales. Estimates are prepared based upon contract quantities and known events. The estimates are reviewed and compared to expected results to verify their accuracy. They are reversed in the following month and replaced with actual results.

At December 31, 2006, the Marketing sales and accounts receivable contained an estimate for December 2006 revenues of $43.6 million.

Estimation of Marketing product purchases:

NGL mix (feedstock) and specification products such as propane, butane and condensate are purchased from facilities located throughout western Canada and in some locations in the United States. The majority of NGL mix purchases are estimated each month as actual volume information is generally not available until the next month. The estimates are prepared based upon a three month rolling average of production volumes for each facility and an estimate of price based upon historical information. Specification product volumes and prices are based upon contract volumes and prices. Accordingly, these financial statements contain an estimate for one month of these purchases.

Marketing cost of goods sold, inventory and accounts payable contained an estimate of NGL product purchases of $77.2 million at December 31, 2006.

Estimation of asset retirement obligation:

Keyera will be responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of its facilities at the end of their economic life. The determination of the estimate of these obligations is based upon settlement between 2018 and 2038. Keyera utilizes a documented process, overseen by the Health, Safety and Environment Committee, to estimate future liability and the anticipated cost of the decommissioning, abandonment and reclamation of its facilities.

Keyera has estimated that at December 31, 2006, the total undiscounted amount required to settle the asset retirement obligations is $183.2 million compared to $168.2 million at December 31, 2005. The discounted net present value of this obligation at December 31, 2006 is $34.5 million compared to $27.8 million at December 31, 2005. The increase in the undiscounted and the discounted amount is primarily due to changes in the estimated future liabilities.

It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed the current estimates which are the basis of the asset retirement obligation shown in Keyera's financial statements.

Additional information related to decommissioning, abandonment and reclamation costs is provided in Keyera's 2007 Annual Information Form, which is available on SEDAR.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and working capital

Cash provided by operating activities before changes in non-cash operating working capital was $103.9 million during 2006. The Fund paid $87.0 million of distributions and dividends during the year and required $68.9 million for capital expenditures, additions to intangibles, inventory and other non-cash working capital. The resulting cash requirement of $52.0 million was funded by $42.1 million of short-term debt, $4.3 million of proceeds from the Distribution Reinvestment Plan ("DRIP") and $5.6 million of internal cash.

A deficiency of $41.1 million in cash and working capital existed at December 31, 2006 compared to a surplus of $9.7 million last year. The decrease in working capital resulted from the use of short-term debt to finance growth capital expenditures.

Additions to Property, Plant and Equipment

(in millions of dollars)	*Twelve months ended December 31* **2006**	2005
Growth capital expenditures	**70.9**	48.4
Maintenance capital expenditures	**3.0**	4.5
Total capital expenditures	**73.9**	52.9

In 2006, additions to property, plant and equipment amounted to $73.9 million, consisting of $3.0 million of maintenance capital and $70.9 million of growth capital. The maintenance capital expenditures were related to numerous small projects. In addition to maintenance capital expenditures, Keyera incurred maintenance and repair expenses of $19.5 million that are included in operating costs. In 2007, Keyera expects to spend approximately $3 to $5 million for maintenance capital projects. In addition, it is anticipated that Keyera will spend between $24 and $28 million for expensed maintenance work.

Keyera's capital program was largely directed at opportunities identified from its existing asset base. The construction projects extended capture areas, expanded capacities and introduced new services at existing plants and facilities. In general, Keyera's engineering team was able to complete these projects on time and on budget, during a year when engineering, procurement and construction challenges were common.

Growth was also achieved through acquisition. Keyera acquired three propane terminals in the United States to expand and vertically integrate its existing NGL marketing business and acquired incremental ownership interests in two pipelines to increase our future share of operating results.

The following were the significant 2006 growth capital expenditures:

- $21.8 million to construct the Caribou North Gas Gathering System and the Aurora pipeline which have extended the capture areas of the plants.
- $12.0 million to acquire storage and terminal facilities in the U.S.
- $13.7 million for plant process improvements, the addition of new compression facilities and the acquisition of incremental ownership interests in the Rimbey Gull Lake pipeline and the Medicine River pipeline.
- $7.6 million to construct the rail facility expansion at the Edmonton terminal to enable the delivery of incremental condensate volumes.
- $4.1 million to complete the Fort Saskatchewan brine pond expansion, to increase the utilization of the underground storage caverns.
- $1.6 million to upgrade the amine and control systems at the Caribou gas plant, increasing plant capacity by 25 million cubic feet per day.

The expected growth capital expenditures for 2007 are between $40 and $60 million, but the actual level of growth capital investment is dependent upon available opportunities.

Working capital requirements are strongly influenced by the volume of NGLs held in storage and their related commodity prices. NGL inventories are required to meet seasonal demand patterns and will vary depending on the time of year. Historically, the largest allocation of working capital to fund inventory has been approximately $81 million. In addition to the working capital required for inventory, Keyera typically utilizes approximately $25 to $35 million to finance the other components of working capital.

Risks

The majority of cash flow is derived from the Gathering and Processing and NGL Infrastructure business segments. The operating income generated from gathering and processing facilities is not significantly exposed to changes in operating costs due to the nature of most fee structures, which provide a mechanism for the recovery of operating costs.

The most significant exposure faced by the Gathering and Processing and NGL Infrastructure businesses over the long term is related to declines in throughput volumes. Without reserve additions, third party production will decline over time as reserves are depleted. Declining production volumes may translate into lower throughput and cash flow at Keyera's plants and facilities. However, these facilities are located in significant natural gas supply areas of the WCSB and have high barriers to entry for new competitors.

Keyera's cash flows may also be adversely affected by the occurrence of common hazards and environmental risks related to the natural gas gathering, processing and pipeline transportation business, such as the failure of equipment, systems or processes, operator error, labour disputes, disputes with owners of interconnected facilities, catastrophic events or acts of terrorism. To mitigate these operational and environmental risks, Keyera maintains written standard operating practices, formally assesses and documents employee competency, and maintains formal inspection, maintenance, safety and environmental programs. In addition, Keyera carries casualty and business interruption insurance, although there can be no assurance that the proceeds of such insurance will compensate Keyera fully for any losses nor can it be assured that such insurance will be available in the future.

The most significant exposure faced by the Marketing business is fluctuation in the prices of the commodities that Keyera buys and sells.

For a further discussion of the risks identified in this MD&A, other risks and trends that could affect the financial performance of the Fund and the steps that Keyera takes to mitigate these risks, readers are referred to the descriptions in this MD&A and to Keyera's 2007 Annual Information Form, which is available on SEDAR.

Keyera's future debt levels are primarily dependent on operating cash flows, working capital requirements and capital investment programs. Management expects the Fund's 2007 capital expenditures and distributions to be funded by cash flow from operations and borrowing on available debt facilities.

Debt Covenants

In order for Keyera to manage seasonal fluctuations in cash flow and working capital, fund growth capital expenditures and stabilize distributions, if required, Keyera has established credit facilities consisting of a $150 million revolving term facility that matures on April 21, 2009 and $25 million of revolving demand facilities. As at December 31, 2006, $101 million was drawn under these credit facilities. Management expects that, upon maturity of these facilities, adequate replacement facilities will be established.

These credit facilities are subject to two major financial covenants: Debt to EBITDA and Debt to Capitalization. The calculation for each ratio is based on specific definitions, is not in accordance with GAAP and cannot be readily replicated by referring to the Fund's financial statements. The definitions in this agreement provide for the deduction of net working capital in the calculation of debt. Following are the ratios as calculated in accordance with the covenants as at December 31, 2006:

Covenant	*Position as at December 31, 2006*
Debt to EBITDA not to exceed 3.50	**2.18**
Debt to Capitalization not to exceed 0.55	**0.26**

Keyera has $215 million of unsecured senior notes. Of that amount, $20 million matures in August 2008 and bears interest at 5.42%, $90 million matures in October 2009 and bears interest at 5.23%, $52.5 million matures in August 2010 and bears interest at 5.79%, and $52.5 million matures in August 2013 and bears interest at 6.16%. These notes are subject to three major financial covenants: Debt to EBITDA, EBITDA to Interest Charges and Priority Debt to Total Assets. The calculations for each of these ratios are based on specified definitions. Following are the ratios as calculated in accordance with the covenants as at December 31, 2006:

Covenant	*Position as at December 31, 2006*
Debt to EBITDA not to exceed 3.50	**2.81**
EBITDA to interest charges not less than 3.00	**9.38**
Priority Debt to Total Assets not to exceed 15%	**0%**

Failure to adhere to the covenants described above may impair Keyera's ability to pay distributions.

Also, a subsidiary of the Partnership has an unsecured revolving credit facility in the amount of $7 million. As at December 31, 2006, $7 million had been drawn under this credit facility. Management expects that upon maturity of these facilities, adequate replacement facilities will be established.

Regulatory risk

On October 31, 2006 the Government of Canada announced a new tax on a portion of the distributions of publicly-traded Canadian income trusts and limited partnerships. The effects of this proposed tax on Keyera are discussed in the Business Environment section of this management's discussion and analysis. A more complete discussion of regulatory risks can be found in Keyera's 2007 Annual Information Form, available on SEDAR.

Credit risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or counterparty. The majority of Keyera's accounts receivable are due from entities in the oil and gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad domestic and international customer base. Keyera evaluates and monitors the financial strength of its customers in accordance with its credit policy.

Management believes these measures minimize Keyera's overall credit risk; however, there can be no assurance that these processes will protect against all losses from non-performance. At December 31, 2006, the accounts receivable from Keyera's two largest customers accounted for less than 1% of accounts receivable (2005 – less than 1%).

With respect to counterparties for financial instruments used for economic hedging purposes, Keyera limits its credit risk through dealing with recognized futures exchanges or investment grade financial institutions and by maintaining credit policies which significantly minimize overall counterparty credit risk.

Marketing risk management

Keyera enters into contracts to purchase and sell natural gas, NGLs and crude oil. Most of these contracts are priced at floating market prices. These activities expose Keyera to market risks resulting from movements in commodity prices between the time volumes are purchased and the time they are sold and from fluctuations in the margins between purchase prices and sales prices.

The prices of the products that are marketed by Keyera are subject to fluctuations as a result of such factors as seasonal demand changes, changes in crude oil and natural gas markets and other factors. In many circumstances, particularly in NGL marketing, purchase and sale contracts are not perfectly matched as they are entered into at different times, locations and values. Further, Keyera normally has a long position in most of the NGL products that it markets and may store NGLs in order to meet seasonal demand and take advantage of seasonal pricing differentials, thereby resulting in inventory risk. Because crude oil margins are earned by capturing spreads between different qualities of crude oil, Keyera's crude oil midstream business is subject to volatility in price differentials between crude oil streams. In both Keyera's NGL and crude oil marketing businesses, margins can vary significantly from period to period and volatility in the markets for these products may cause distortions in financial results from period to period that are not replicable.

To some extent, Keyera can lessen certain elements of risk exposure through the integration of its Marketing business with its Facilities businesses. In spite of this integration, Keyera remains exposed to market and commodity price risk. Keyera manages this commodity risk in a number of ways, including the use of financial contracts and by offsetting some physical and financial contracts in terms of volumes, timing of performance and delivery obligations. For example, in the context of NGL marketing, because NGL product prices are related to the price of crude oil, crude oil financial contracts are one of the more common hedging strategies that Keyera uses. This strategy is subject to basis risk between the prices of crude oil and the NGL product and therefore cannot be expected to fully offset future propane, butane and condensate price movements. Further, there is no guarantee that hedging and other efforts to manage the marketing and inventory risks will generate profits or mitigate all the market and inventory risk associated with these activities. If Keyera hedges its commodity price exposure, it may also forego the benefits that may otherwise be experienced if commodity prices were to increase. To the extent that Keyera engages in these kinds of hedging activities, it is also subject to credit risks associated with counterparties with whom it contracts.

Foreign currency rate risk

The Gathering and Processing and NGL Infrastructure segments generated 59% of 2006 operating margin and are not subject to foreign currency rate risk. All sales and virtually all purchases are denominated in Canadian dollars. In the Marketing business, approximately US$313.2 million of sales were priced in U.S. dollars in 2006.

Commitments

Keyera has assumed various contractual obligations in the normal course of its operations. At December 31, 2006, the obligations that represent known future cash payments that are required under existing contractual arrangements are as follows:

Contractual obligations

	Payments Due by Period (in thousands of dollars)				
	Total	1 Year	2 – 3 Years	4 – 5 Years	After 5 Years
Long-term debt[1]	**215,000**	–.	110,000	52,500	52,500
Capital lease obligations	**-**	–	–	–	–
Operating leases[2]	**31,197**	8,480	13,046	6,171	3,500
Purchase obligations[3]	**-**	–	–	–	-
Total contractual obligations	**246,197**	8,480	123,046	58,671	56,000

[1] *Long-term debt obligations do not include interest payments.*

[2] *Keyera has lease commitments relating to railway tank cars, vehicles, computer hardware, office space, terminal space and natural gas transportation.*

[3] *Keyera is involved in various contractual agreements with ConocoPhillips and other producers to purchase NGLs. These agreements range from one to twelve years and in general obligate Keyera to purchase all product produced at specified locations on a best efforts basis. The purchase prices are based on then current period market prices. The future volumes and prices for these contracts cannot be reasonably determined.*

Control Environment

Disclosure Controls and Procedures

As of December 31, 2006, the Chief Executive Officer and the Chief Financial Officer together with Keyera's management have evaluated the design and effectiveness of Keyera's disclosure controls and procedures. They concluded that, as of the end of the period covered by this report, Keyera's disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Fund and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

Internal Control Over Financial Reporting

As of December 31, 2006, under the supervision of and with the participation of Keyera's management, including the Chief Executive Officer and the Chief Financial Officer, internal control over financial reporting has been designed and maintained in order to provide reasonable assurance regarding the reliability of financial reporting. During the quarter ended December 31, 2006, there have been no material changes in internal control over financial reporting.

Unitholder Distributions

Keyera pays distributions to unitholders from its distributable cash flow. The Fund declared $86.6 million of distributions to unitholders in 2006. The Fund's distributable cash flow of $99.7 million was sufficient to fund all the distributions made to unitholders. In determining the level of distributions to unitholders, the Board of Directors takes into consideration current and expected future levels of cash flow, growth capital expenditures, debt repayments, working capital requirements and other factors.

The following table presents the calculation of "distributable cash flow" for the Fund. Keyera management believes that the distributable cash flow is an appropriate measure of the Fund's cash flow available for distribution to Unitholders. Because distributable cash flow is a non GAAP measure, it may not be comparable to similar measures reported by other business entities. Therefore, when assessing Keyera's performance relative to other entities, "cash flow from operating activities" as presented in the Fund's Consolidated Statements of Cash Flows may be a more comparable measure.

Distributable Cash Flow

	Three months ended December 31,		*Twelve months ended December 31,*	
	2006	2005	**2006**	2005
(in thousands of dollars) (unaudited)	**$**	$	**$**	$
Net earnings	**14,928**	15,491	68,078	60,680
Add (deduct):				
Depreciation and amortization	**10,413**	9,502	39,843	36,887
Accretion expense	**809**	788	2,257	2,048
Impairment expense	**–**	–	373	1,160
Unrealized (gain) loss on financial instruments	**153**	783	(491)	280
Future income tax (recovery) expense	**1,800**	231	(7,042)	2,411
Non-controlling interest	**235**	175	1,025	704
Asset retirement obligation expenditures	**(79)**	(78)	(160)	(183)
Maintenance capital	**(288)**	(2,902)	(3,011)	(4,472)
Non-controlling interest distributable cash flow	**(285)**	(188)	(1,153)	(782)
Distributable cash flow	**27,686**	23,802	99,719	98,733
Distributions to unitholders	**21,742**	21,062	86,605	78,541

The business of the Fund is subject to operational and commercial risks that could adversely affect future operating results, earnings, cash flow and distributions to unitholders. These risks include declines in throughput, operational problems and hazards, cost overruns, increased competition, regulatory intervention, environmental considerations, uncertainty of abandonment costs and dependence upon key personnel. These risks are identified and discussed in greater detail in the most recent Annual Information Form available on www.sedar.com as well as in the "Business Environment", "Results of Operations – Marketing" and "Liquidity and Capital Resources" sections of this MD&A.

Standard and Poor's has assigned the Fund an SR-3 stability rating, indicating the expectation of a high level of stability in distributions.

Units and Convertible Debentures

During 2006, $7.2 million of convertible debentures (before adjustment for deferred financing costs) were converted into 597,563 trust units and 207,997 trust units were issued under the DRIP in consideration of $4.3 million, bringing the total units outstanding at December 31, 2006 to 60,930,753. Convertible debentures outstanding at year end were $23.5 million.

Subsequent to December 31, 2006, a further $0.2 million of convertible debentures were converted into 20,664 trust units, and 33,021 trust units were issued to unitholders enrolled in the DRIP in consideration for $0.5 million, bringing the total units outstanding at February 23, 2007 to 60,984,438. Convertible debentures outstanding at February 23, 2007 were $23.3 million, which if converted would add 1,941,166 trust units to those outstanding.

NEW ACCOUNTING PRONOUNCEMENTS

Financial Instruments

In 2005, the CICA issued the following sections in order to increase harmonization with U.S and International accounting standards:

- 1530, Comprehensive Income;
- 3251, Equity;
- 3855, Financial Instruments – Recognition and Measurement; and
- 3865, Hedges.

Effective January 1, 2007, the Trust will be adopting these new standards. All financial assets will be measured at fair value, with the exception of accounts receivable, which will be measured at cost. All financial liabilities, including derivatives, will be measured at fair value when they are classified as held for trading. The new standards expand the definition of derivatives to include both financial and non-financial contracts. Non-financial contracts would include an agreement to buy or sell a commodity for a fixed price at a future date.

Gains and losses on financial instruments measured at fair value will be recognized in net income in the periods they arise.

Section 3865, Hedges, addresses how hedge accounting is to be performed and requires all gains and losses relating to ineffective hedges to be recorded in net income immediately. Unrealized gains and losses relating to effective cash flow hedges are recognized in "other comprehensive income".

As of January 1, 2007, Keyera will determine the fair value of the existing natural gas and electricity hedge contracts, as well as the fair value of all fixed price commodity contracts not previously recognized. On January 1, 2007, Keyera recorded $1.0 million as an asset held for trading and $0.1 million as a liability held for trading to recognize the fair values of these contracts. A corresponding adjustment will be made to opening retained earnings. Subsequent changes in the fair value of the positions will be recorded in net income.

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards over a transitional period. The Accounting Standards Board is expected to develop and publish a detailed implementation plan with a transition period expected to be approximately five years. This convergence initiative is in its early stages as of the date of these annual consolidated financial statements. Accordingly, it would be premature to assess the impact of the initiative, if any, on Keyera at this time.

SELECTED FINANCIAL INFORMATION

The following table presents selected annual financial information for the Fund:

(in thousands of dollars, except per unit information)	2004	2005	**2006**
Operating revenues:			
Marketing	631,696	1,013,334	**1,161,899**
Facilities[1] *(Gathering and Processing and NGL Infrastructure)*	112,906	174,233	**206,624**
Net earnings	22,738	60,680	**68,078**
Net earnings per unit *($/unit)*:			
Basic	0.63	1.03	**1.12**
Diluted	0.55	0.96	**1.10**
Distributions to unitholders	42,037	78,541	**86,605**
Distributions to unitholders per unit *($/unit)*	1.16	1.33	**1.43**
Trust Units outstanding *(thousands)*			
Weighted average *(basic)*	36,199	58,947	**60,604**
Weighted average *(diluted)*	40,941	63,075	**62,794**
Total assets	1,146,757	1,218,160	**1,223,012**
Total long-term financial liabilities	371,000	345,955	**338,499**

[1] *For 2004, revenue from the facilities segment includes $598 of equity earnings relating to Rimbey Pipe Line.*

2006 compared to 2005

For 2006 revenues from Marketing were $1,162 million, an increase of $148.6 million compared to the previous year. Approximately $52.3 million of the increase was due to the growth of the crude oil midstream business that commenced operation in the fourth quarter of 2005. Also included in revenue was $7.0 million related to the settlement and change in fair value of financial contracts that were part of Keyera's risk management program. The remainder was primarily due to higher NGL volumes and prices compared to last year.

Revenues from facilities were $206.6 million, up $32.4 million compared to 2005.

Gathering and Processing revenue for 2006 was $166.7 million, an increase of $27.5 million, or 20%, compared to the previous year. The increase was due primarily to higher throughput in the West Central Region, increasing sour raw gas volumes, which attract a higher processing fee, at the Brazeau River gas plant, the recovery of expenses incurred during the Chinchaga and Strachan gas plant maintenance turnarounds and increased ownership in the Strachan gas plant for the full year.

NGL Infrastructure revenue for 2006 was $39.9 million, an increase of $4.9 million, or 14%, compared to the previous year. The increase was primarily due to higher storage revenues at Keyera's Fort Saskatchewan facility, as well as a non-recurring adjustment of approximately $1 million earned upon the expiration of a long-term contract in the first quarter of 2006.

Consolidated net earnings for 2006 were $68.1 million, an increase of $7.4 million from 2005. This increase was primarily attributable to the strong contribution of the storage business in the NGL Infrastructure segment, lower long-term incentive plan costs in the general and administrative expenses and the recovery of future income taxes in the second quarter of 2006. Partially offsetting this were lower operating margins experienced in the third and fourth quarters of 2006 in the Marketing segment, primarily attributable to the weakening of product prices.

The Fund declared $86.6 million of distributions to unitholders in 2006, an increase of $8.1 million. The increase was due to a higher number of units outstanding as a result of conversions of debentures, the DRIP and higher average distributions per unit in 2006.

2005 compared to 2004

For 2005, revenues from Marketing were $1,013 million, up $381.6 million compared to 2004. Approximately $169.0 million of this increase was due to the consolidation of the Partnership beginning on April 1, 2004. The remainder of the increase was largely due to higher sales volumes and historically high commodity prices.

Revenues from facilities were $174.2 million, up $61.3 million compared to 2004. Approximately $28.4 million of this increase was attributable to the inclusion of revenue from the Partnership and Rimbey Pipe Line, which were not consolidated until April 1, 2004 and July 2, 2004 respectively. The remainder of the increase was largely due to the inclusion of the facilities acquired from EnerPro for the full year of 2005.

Net earnings for 2005 were $60.7 million, up $38.0 million compared to 2004. The increase in net earnings was largely due to the consolidation of the Partnership, Rimbey Pipe Line and the EnerPro assets for the full year of 2005. In addition, stronger Marketing results also contributed to higher net earnings in 2005. This growth was partly offset by higher general and administrative costs, interest expense and depreciation charges.

In 2005, distributions to unitholders increased by $36.5 million due to a higher number of units outstanding as a result of conversions of debentures into trust units. In addition, the Fund increased per unit distributions by approximately 16% compared to 2004.

The following table presents selected financial information for the Fund:

Three months ended (in thousands of dollars)	*Mar 31,* 2005	*Jun 30,* 2005	*Sep 30,* 2005	*Dec 31,* 2005	***Mar 31,*** **2006**	***Jun 30,*** **2006**	***Sep 30,*** **2006**	***Dec 31,*** **2006**
Operating revenues:								
Marketing	228,767	223,590	243,114	317,863	**316,841**	**279,241**	**279,492**	**286,325**
Gathering and Processing	30,552	35,516	35,927	37,278	**38,053**	**40,772**	**44,290**	**43,621**
NGL Infrastructure	8,829	7,276	8,506	10,349	**9,606**	**8,549**	**10,878**	**10,855**
Net earnings	17,832	11,157	16,200	15,491	**15,384**	**25,969**	**11,797**	**14,928**
Net earnings per unit *($/unit)*								
Basic	0.31	0.19	0.27	0.26	**0.26**	**0.43**	**0.19**	**0.25**
Diluted	0.28	0.17	0.25	0.23	**0.22**	**0.39**	**0.16**	**0.24**
Trust units outstanding *(thousands)*								
Weighted average *(basic)*	57,761	58,596	59,475	59,926	**60,291**	**60,560**	**60,692**	**60,865**
Weighted average *(diluted)*	62,989	62,988	63,194	63,246	**63,321**	**62,768**	**62,817**	**62,869**
Distributions to unitholders	17,924	19,332	20,223	21,062	**21,553**	**21,631**	**21,679**	**21,742**

December 31, 2006 compared to September 30, 2006

Marketing revenues of $286.3 million in the fourth quarter of 2006 increased from the third quarter of 2006 by $6.8 million. This increase was largely due to the seasonal increase in sales volumes.

In the fourth quarter of 2006, Gathering and Processing revenue of $43.6 million decreased by $0.7 million due to lower revenues at the Chinchaga and Strachan plants. This decrease was partly offset by higher revenues experienced in the West Central region.

NGL Infrastructure revenue of $10.9 million was consistent with the prior quarter.

Net earnings were $14.9 million, an increase of $3.1 million due to higher margins experienced in the NGL Infrastructure segment and lower Gathering and Processing expenses.

September 30, 2006 compared to June 30, 2006

Third quarter Marketing revenues of $279.5 million increased from the prior quarter by $0.3 million. This increase was primarily due to the settlement of financial contracts partly offset by lower NGL sales volumes.

Gathering and Processing revenue of $44.3 million increased by $3.5 million due to higher throughput in the West Central Region, the increasingly sour gas at the Brazeau River gas plant which attracts a higher processing fee and the recovery of expenses incurred during the Chinchaga gas plant turnaround.

NGL Infrastructure revenue of $10.9 million increased by $2.3 million primarily due to increased NGL storage revenues at Fort Saskatchewan.

Net earnings were $11.8 million a decrease of $14.2 million from previous quarter. This decrease was primarily due to the recovery of future income taxes experienced in the second quarter.

June 30, 2006 compared to March 31, 2006

For the second quarter of 2006, Marketing revenues of $279.2 million decreased by $37.6 million from the prior quarter. This decrease in revenues was due primarily to a seasonal decline in sales volumes.

Gathering and Processing revenue of $40.8 million increased by $2.7 million primarily due to higher throughput volumes in the West Central Region and increased ownership in the Strachan gas plant.

NGL Infrastructure revenue of $8.5 million decreased by $1.1 million in comparison to the first quarter of 2006 due to a non-recurring final contract adjustment experienced in the first quarter.

Net earnings were $26.0 million, an increase of $10.6 million from the prior quarter. This increase in earnings was primarily attributable to the recovery of future income taxes resulting from the reduction of statutory tax rates in future years.

March 31, 2006 compared to December 31, 2005

Marketing revenues of $316.8 million decreased by $1.0 million due to a slight softening of propane margins attributed to warmer than seasonal weather.

Gathering and Processing revenue for the first quarter of 2006 was $38.1 million, an increase of $0.8 million from the prior quarter. The increase was due to higher throughput volumes and the acquisition of an incremental 25% ownership interest in the Strachan gas plant in December 2005.

For the first quarter of 2006, operating revenues from NGL Infrastructure were $9.6 million, down $0.7 million from the prior quarter. This decrease was primarily due to lower fractionation revenues, and the result of lower throughput caused by equipment fouling at the Fort Saskatchewan facility. This decrease was partly offset by a non-recurring final adjustment upon expiration of a long-term contract.

Net earnings were $15.4 million, a decrease of $0.1 million from the previous quarter. This decrease was primarily due to higher income tax expenses. The effect of the higher income tax was partly offset by higher operating margins and lower general and administrative costs.

December 31, 2005 compared to September 30, 2005

For the fourth quarter of 2005, Marketing revenues of $317.9 million increased by $74.7 million compared to the previous quarter. This increase was largely due to the seasonal increase in sales volumes.

For the fourth quarter of 2005, Gathering and Processing revenues of $37.3 million increased by $1.4 million compared to the previous quarter. NGL Infrastructure revenues of $10.3 million increased by $1.8 million compared to the previous quarter. These increases were primarily due to higher throughput volumes and increased flow-through of operating costs.

Net earnings were $15.5 million in the fourth quarter of 2005, down $0.7 million from the previous quarter. This decrease was primarily due to higher general and administrative costs, interest and depreciation charges. The effect of these higher costs was partly offset by the strong Marketing results achieved in the fourth quarter.

September 30, 2005 compared to June 30, 2005

For the third quarter of 2005, Marketing revenues of $243.1 million increased by $19.5 million compared to the previous quarter. This increase was largely due to continued demand for butane and condensate. The price of propane also strengthened in the third quarter of 2005.

For the third quarter of 2005, operating revenues from the Gathering and Processing segment was $35.9 million, up $0.4 million compared to the previous quarter. Operating revenues from the NGL Infrastructure segment were $8.5 million, up $1.2 million compared to the previous quarter. These increases were due to prior period fee recoveries and higher revenues from services.

Net earnings were $16.2 million in the third quarter of 2005, up $5.0 million from the previous quarter. This increase was primarily due to stronger results from facilities in the third quarter as well as lower general and administrative costs and the recognition of an impairment expense of $1.2 million in the second quarter of 2005.

June 30, 2005 compared to March 31, 2005

For the second quarter of 2005, Marketing revenues of $223.6 million decreased by $5.2 million compared to the prior quarter. The decrease in revenues was primarily due to a seasonal decrease in sales volumes that was partially offset by strong condensate and butane price premiums.

Operating revenues from Gathering and Processing for the second quarter of 2005 was $35.5 million, up $5.0 million from the previous quarter. This increase in revenue was largely due to the return of volumes from the Caribou and Strachan plants that experienced unplanned outages in the first quarter of 2005. In addition, volumes were redirected to the Strachan plant in the second quarter due to third party plant turnarounds. This increase was partly offset by a decrease of NGL Infrastructure revenue of $7.3 million, down $1.6 million from prior quarter.

Net earnings were $11.2 million in the second quarter, down by $6.7 million compared to the first quarter of 2005. This decrease was primarily due to weaker Marketing results and an increase in general and administrative costs. General and administrative costs were higher in the second quarter due to higher incentive plan costs. Also in the second quarter, an impairment expense of $1.2 million was recorded to reflect management's decision to dispose of a small, non-core gas processing plant.

Management's Report

Management is responsible for the preparation of the accompanying consolidated financial statements. These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles and include amounts that are based on estimates and informed judgements. Financial information contained throughout this Financial Report is consistent with these consolidated financial statements.

Management has overall responsibility for internal controls and has developed and maintains a system of internal controls that provides reasonable assurance that the financial statements realistically report the Company's operating and financial results and that the Company's assets are safeguarded.

Deloitte & Touche LLP, independent external auditors, appointed by the Board of Directors, have independently examined the enclosed consolidated financial statements. The Audit Committee, consisting of independent directors, has reviewed the consolidated financial statements with management and the external auditors and has reported to the Board of Directors. The Board has approved the consolidated financial statements.

Jim V. Bertram
President and Chief Executive Office

David G. Smith
Senior Vice President and Chief Financial Officer

February 22, 2007

Auditors' Report

To the Unitholders of Keyera Facilities Income Fund

We have audited the consolidated statements of financial position of Keyera Facilities Income Fund as at December 31, 2006 and 2005 and the consolidated statements of earnings, accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the management of Keyera Energy Management Ltd. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Keyera Facilities Income Fund as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Canada

February 22, 2007

Consolidated Statements of Financial Position

As at December 31 *(All amounts expressed in thousands of Canadian dollars)*	2006 $	2005 $
ASSETS		
Current assets		
Cash and cash equivalents	**–**	5,634
Accounts receivable	**160,112**	191,259
Inventory	**53,939**	53,205
Assets held for sale *(note 4)*	**4,200**	–
Other current assets	**4,327**	4,042
	222,578	254,140
Property, plant and equipment *(note 3)*	**924,947**	881,330
Assets held for sale *(note 4)*	**–**	4,573
Intangible assets *(note 5)*	**75,487**	78,117
	1,223,012	1,218,160
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	**96**	–
Accounts payable and accrued liabilities	**148,318**	171,316
Distributions payable *(note 11)*	**7,251**	7,155
Credit facilities *(note 6)*	**107,984**	66,000
	263,649	244,471
Long-term debt *(note 6)*	**215,000**	215,000
Convertible debentures *(note 7)*	**23,542**	30,713
Asset retirement obligation *(note 8)*	**34,533**	27,776
Future income tax liability *(note 9)*	**65,424**	72,466
	602,148	590,426
Non-controlling interest	**2,744**	2,198
Unitholders' equity		
Unitholders' capital *(note 10)*	**677,025**	665,914
Accumulated earnings	**159,083**	91,005
Accumulated cash distributions to unitholders *(note 11)*	**(217,988)**	(131,383)
	618,120	625,536
	1,223,012	1,218,160

Commitments and contingencies *(note 14)*

SEE ACCOMPANYING NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Approved on behalf of the Fund by its administrator, Keyera Energy Management Ltd.:

Wesley R. Twiss
Director

James V. Bertram
Director

Consolidated Statements of Earnings and Accumulated Earnings

For the Years Ended December 31 *(All amounts expressed in thousands of Canadian dollars, except per unit information)*	2006 $	2005 $
Operating revenues		
Marketing sales	**1,161,899**	1,013,334
Gathering and Processing	**166,736**	139,274
NGL Infrastructure	**39,888**	34,959
	1,368,523	1,187,567
Operating expenses		
Marketing cost of goods sold	**1,102,045**	946,263
Gathering and Processing	**96,558**	67,469
NGL Infrastructure	**23,956**	24,296
	1,222,559	1,038,028
	145,964	149,539
General and administrative	**18,892**	25,217
Interest expense	**18,156**	16,213
Depreciation and amortization	**39,843**	36,887
Accretion expense *(note 8)*	**2,257**	2,048
Impairment expense	**373**	1,160
	79,521	81,525
Earnings before tax and non-controlling interest	**66,443**	68,014
Income tax (recovery) expense *(note 9)*	**(2,660)**	6,630
Earnings before non-controlling interest	**69,103**	61,384
Non-controlling interest	**1,025**	704
Net earnings	**68,078**	60,680
Accumulated earnings, beginning of year	**91,005**	30,325
Accumulated earnings, end of year	**159,083**	91,005
Weighted average number of units *(thousands) (note 10)*		
– basic	**60,604**	58,947
– diluted	**62,794**	63,075
Net earnings per unit *(note 10)*		
– basic	**1.12**	1.03
– diluted	**1.10**	0.96

SEE ACCOMPANYING NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Statements of Cash Flows

For the Years Ended December 31 *(All amounts expressed in thousands of Canadian dollars)*	2006 $	2005 $
Net inflow (outflow) of cash:		
Operating activities		
Net earnings	**68,078**	60,680
Items not affecting cash:		
Depreciation and amortization	**39,843**	36,887
Accretion expense	**2,257**	2,048
Impairment expense	**373**	1,160
Unrealized (gain) loss on financial instruments	**(491)**	280
Future income tax (recovery) expense *(note 9)*	**(7,042)**	2,411
Non-controlling interest	**1,025**	704
Asset retirement obligation expenditures *(note 8)*	**(160)**	(183)
Changes in non-cash operating working capital	**6,773**	(41,840)
	110,656	62,147
Investing activities		
Additions to property, plant and equipment	**(73,868)**	(52,870)
Additions to intangibles	**(1,115)**	–
Proceeds on sale of assets	**–**	907
Changes in non-cash working capital	**(651)**	4,951
	(75,634)	(47,012)
Financing activities		
Proceeds from credit facilities	**41,984**	54,000
Issuance of trust units *(note 10)*	**4,252**	2,175
Distributions paid to unitholders *(note 11)*	**(86,509)**	(77,013)
Distributions or dividends paid to others	**(479)**	(506)
	(40,752)	(21,344)
Net cash (outflow) inflow	**(5,730)**	(6,209)
Cash and cash equivalents, beginning of year	**5,634**	11,843
Cash (bank indebtedness), end of year	**(96)**	5,634

SEE ACCOMPANYING NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
SEE NOTE 15 FOR CASH INTEREST AND TAXES PAID

Notes to Consolidated Financial Statements

For the years ended December 31, 2006 and 2005
(All amounts expressed in thousands of Canadian dollars, except where otherwise noted)

1. STRUCTURE OF THE FUND

Keyera Facilities Income Fund (the "Fund") is an unincorporated open-ended trust established under the laws of the Province of Alberta pursuant to the Fund Declaration of Trust dated April 3, 2003. The Fund indirectly owns a 100% interest in Keyera Energy Partnership (the "Partnership").

The Partnership is involved in the business of natural gas gathering and processing, as well as natural gas liquids ("NGLs") and crude oil processing, transportation, storage and marketing in Canada and the U.S. Its wholly-owned subsidiaries include Keyera Energy Facilities Ltd. ("KEFL"), Keyera Energy Ltd. ("KEL") and Keyera Energy Inc. ("KEI").

The Fund is administered by and the Partnership is managed by Keyera Energy Management Ltd. ("KEML" or the "Managing Partner"). The Managing Partner has a 33.83% interest in the Partnership.

The Fund makes monthly cash distributions to unitholders of record on the last business day of each month. The amount of the distributions per trust unit are equal to the pro rata share of the distribution received indirectly from the Partnership and, in the event of the termination of the Fund, participating pro rata in the net assets remaining after satisfaction of all liabilities.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Fund and all controlled entities. All subsidiary companies, with the exception of Rimbey Pipe Line Co. Ltd. ("RPL"), are wholly-owned. The non-Fund ownership interest in RPL has been included in the consolidated financial statements and is shown as a non-controlling interest. All material intercompany accounts and transactions have been eliminated upon consolidation.

Measurement uncertainty

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These include the recoverability of assets and the amounts recorded for depreciation, amortization, accretion and asset retirement obligations, which depend on estimates of oil and gas reserves or the economic lives and future cash flows from related assets. The recognized amounts of such items are based on management's best information and judgment.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Revenues and expenses are translated at rates of exchange in effect at the transaction date. Exchange gains and losses are recorded in earnings in the period they are incurred.

Revenue recognition

Marketing revenue

Revenue consisting primarily of marketing NGLs and crude oil midstream activities, is recognized based on volumes delivered to customers at contractual delivery points and rates.

Gathering and Processing revenue

Gathering and Processing revenue is recognized through fixed fee arrangements or flow-through arrangements that are designed to recover operating costs and provide a return on capital. Amounts collected in excess of the recoverable amounts under flow-through arrangements are recorded as a current liability. Recoverable amounts in excess of the amounts collected under flow-through arrangements are recorded as a current receivable. Revenue from take or pay arrangements is recognized as service is provided or upon expiry of the commitment, whichever occurs later.

NGL Infrastructure revenue

Revenue from transportation, processing and storage of NGLs is recognized through fee-for-service arrangements. The fee is comprised of a fixed charge per unit transported or processed. Revenue is recognized when services have been performed.

Joint ventures

Substantially all gathering and processing and NGL infrastructure activities are conducted jointly with others, and accordingly these financial statements reflect only the Fund's indirect proportionate interest in such activities.

Financial instruments

Derivative financial instruments are utilized by the Fund through its ownership in the Partnership to mitigate its exposure to fluctuations in the price of natural gas, NGLs, electricity and currency exchange rates. The Fund uses a variety of instruments to manage these exposures including swaps and options. Gains and losses related to derivative contracts are recognized in Marketing revenue.

The Fund may elect to use hedge accounting. To be accounted for as a hedge, a derivative financial instrument must be designated and documented as a hedge and must be effective at inception and on an on going basis. The documentation defines the relationships between the hedging items and the hedged items and documents the objectives and strategies for undertaking various hedge transactions. The process includes linking derivative financial instruments to specific anticipated transactions. The Fund also formally assesses, both at the inception of the hedge and on an ongoing basis, whether the instrument used is highly effective in offsetting changes in cash flows or fair values of the hedged item. Hedge effectiveness is achieved if the cash flows from the hedging item substantially offset the cash flows of the hedged item and the timing of the cash flows is similar or if changes in the fair value of the financial instrument substantially offset changes in the fair value of the related asset or liability.

If designated as a hedge, gains and losses on these instruments are deferred and recognized in earnings in the same period as the hedged item. The fair value of derivative financial instruments qualifying for hedge accounting is not recorded on the consolidated statements of financial position. When a hedging derivative financial instrument matures, expires, is sold, terminated or cancelled and is not replaced as part of the Fund's hedging strategy, the termination gain or loss is deferred and recognized when the gain or loss on the hedged item is recognized. If a designated hedged item matures, expires, is sold, extinguished or terminated and the hedged item is no longer probable of occurring, any previously deferred amounts associated with the hedging item are recognized in current earnings along with the corresponding gains or losses recognized on the hedged item. If a hedging relationship is terminated or ceases to be effective, hedge accounting is not applied to subsequent gains or losses. Any previously deferred amounts are carried forward and recognized in earnings in the same period as the underlying hedged item.

Where a financial instrument is not designated as a hedge or does not meet the criteria for hedge accounting, it is recorded on the consolidated statement of financial position at its fair value, either as an asset or as a liability. Changes in the fair value of these financial instruments are recognized in earnings in the period in which they occur.

Cash and cash equivalents

Cash and cash equivalents include short-term investments with maturity of three months or less when purchased.

Inventory

Inventory is comprised primarily of NGL product for sale through the marketing operations. Inventory is valued at the lower of cost and net realizable value. Cost is determined on a weighted average cost basis, calculated monthly.

Property, plant and equipment

Property, plant and equipment consist primarily of natural gas processing and gathering systems, NGL infrastructure facilities and marketing storage facilities, which were recorded at cost. Depreciation of these facilities is provided for on a straight-line basis over the estimated useful life of each facility. The depreciation periods range from six to thirty-three years for Gathering and Processing, thirteen to thirty-two years for NGL Infrastructure, three to twenty-five years for Marketing and seven to twenty-three years for corporate assets.

Impairment on property, plant and equipment is measured in a two-step process. Step one calculates the fair value, determined by the undiscounted future cash flows of the asset or asset group. Step two determines the impairment amount, equal to the difference between the carrying amount and fair value.

Intangible assets

Goodwill

Keyera's goodwill resulted from business combinations and represents the portion of purchase price that was in excess of the fair value of net assets acquired. Goodwill is recorded at cost and is not subject to amortization. It is tested at least annually for impairment by comparing the estimated future cash flows of a reporting unit, to which the goodwill is attributable, to its book value.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Other intangible assets

Other intangible assets consist of the marketing business contributed by the partners upon formation of the Partnership and marketing business contracts acquired on business combinations and asset purchases. These assets were recorded at fair market value upon initial recognition and are being amortized over their estimated economic life. The unamortized balance of these intangible assets is assessed periodically for impairment based on management's best estimates of future net revenues from the Marketing business.

Deferred financing costs

Deferred financing fees consist of transaction costs incurred to obtain financing. These assets were recorded at cost and are being amortized on a straight-line basis over the term of their related debt offering.

Asset retirement obligation

The asset retirement cost, deemed to be the fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset and allocated to expense on a basis consistent with depreciation and amortization. Amortization of asset retirement costs is included in depreciation and amortization in the consolidated statement of earnings. The amount of the liability is revised periodically in accordance with changes in the assumptions and estimates underlying the calculations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion expense in the consolidated statement of earnings, over the estimated time period until settlement of the obligation. Actual expenditures incurred are charged against the asset retirement obligation.

Income taxes

Under the terms of the Canadian Income Tax Act, the Fund is considered to be a "mutual fund trust" and is taxable only to the extent that its income is not distributed or distributable to its unitholders. The Fund is contractually committed to distribute to its unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable in its hands.

All subsidiaries of the Fund follow the liability method of accounting for income taxes. Under this method, these subsidiaries record the future income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect a change in the income tax rates and the adjustment is recognized in earnings in the period in which the change occurs.

Unit-based compensation

The Fund has a Long Term Incentive Plan ("LTIP"), which is disclosed in note 12. The LTIP is a stock appreciation right as defined by the Canadian Institute of Chartered Accountants. The difference between the market price of the trust units and the grant price for the outstanding units multiplied by the number of rights is recognized as compensation expense, over the vesting period. Fluctuations in the price of the trust units will change the accrued compensation expense and are recognized when they occur.

Net earnings per unit

Basic net earnings per unit are calculated by dividing net earnings, by the weighted average number of units outstanding during the period. For the calculation of the weighted average number, trust units are determined to be outstanding from the date they are issued. Diluted net earnings per unit is calculated by adding the weighted average number of units outstanding during the period to the additional units that would have been outstanding if potentially dilutive units had been issued, using the "treasury stock" method.

Distributions to unitholders

The monthly amount of the distributions to unitholders of the Fund is defined in the Fund Declaration of Trust. The computation of the distributions to unitholders is comprised of cash amounts received or receivable as distributions or interest income and any net proceeds from the issuance of trust units, less any amounts that relate to the redemption of trust units and any expenditures of the Fund.

3. PROPERTY, PLANT AND EQUIPMENT

	Cost $	Accumulated Depreciation $	Net Book Value $
As at December 31, 2006			
Gathering and Processing	**859,540**	**(145,251)**	**714,289**
NGL Infrastructure	**231,709**	**(36,467)**	**195,242**
Marketing	**12,179**	**(254)**	**11,925**
Corporate and other	**8,616**	**(5,125)**	**3,491**
Total	**1,112,044**	**(187,097)**	**924,947**
As at December 31, 2005			
Gathering and Processing	808,225	(117,014)	691,211
NGL Infrastructure	216,932	(28,760)	188,172
Marketing	–	–	–
Corporate and other	6,860	(4,913)	1,947
Total	1,032,017	(150,687)	881,330

Costs associated with assets under development, excluded from costs subject to depreciation, totaled $1,757 as at December 31, 2006 (2005 – $10,823).

4. ASSET HELD FOR SALE

Asset held for sale consists of an interest in an electrical generator. In 2005, a portion of the equipment was sold for proceeds of $162. In 2006, the equipment was written down to its estimated net realizable value, recognizing a $373 charge to impairment expense. On January 23, 2007, the Fund sold its interest in the electrical generator for $4,200.

5. INTANGIBLE ASSETS

	Cost $	Accumulated Amortization $	Net Book Value $
As at December 31, 2006			
Gathering and Processing *(a)*	**39,219**	**–**	**39,219**
NGL Infrastructure *(a)*	**25,715**	**–**	**25,715**
Marketing *(b)*	**19,290**	**(10,223)**	**9,067**
Corporate and other *(c)*	**3,333**	**(1,847)**	**1,486**
Total	**87,557**	**(12,070)**	**75,487**
As at December, 31, 2005			
Gathering and Processing *(a)*	39,219	–	39,219
NGL Infrastructure *(a)*	25,715	–	25,715
Marketing *(b)*	18,175	(7,178)	10,997
Corporate and other *(c)*	3,645	(1,459)	2,186
Total	86,754	(8,637)	78,117

5. INTANGIBLE ASSETS (continued)

(a) Gathering and Processing and NGL Infrastructure segments intangible assets consist of goodwill.

(b) The Marketing segment intangible assets are other intangible assets. Other intangible assets consist of the marketing business contributed by the Partners when the Partnership was first formed, the marketing business of EnerPro acquired in 2004 and the marketing contracts acquired with the U.S. propane terminals in 2006. These assets are being amortized over the remaining economic life of less than a year to seven years.

(c) The corporate segment intangible assets relate to deferred financing fees. Long-term debt deferred financing fees are discussed further in note 6. Convertible debenture deferred financing fees are discussed further in note 7.

6. CREDIT FACILITIES AND LONG-TERM DEBT

As at December 31	**2006** **$**	2005 $
Bank credit facilities *(a)*	**100,984**	63,000
Revolving demand loan *(d)*	**7,000**	3,000
Total credit facilities	**107,984**	66,000
Long-term debt *(b & c)*	**215,000**	215,000

(a) The Partnership has a $150,000 unsecured revolving credit facility with certain Canadian financial institutions led by the Royal Bank of Canada. The facility has a three year revolving term and matures on April 21, 2009, unless extended. In addition, the Royal Bank of Canada has provided a $15,000 revolving demand facility and the Toronto Dominion Bank has provided a $10,000 revolving demand facility. The revolving credit facilities bear interest based on the lenders' rates for Canadian prime commercial loans, U.S. Base rate loans, Libor loans or Bankers' Acceptances rates. The weighted average interest rate for the year ended December 31, 2006 was 5.43% (2005 – 4.40%). As at December 31, 2006, the balance outstanding on the bank credit facilities was $100,984 (2005 – $63,000).

(b) In 2003, $125,000 of unsecured senior notes were issued by the Partnership and KEFL in three parts: Series A of $52,500 due in 2010, bearing interest at 5.79%, Series B of $52,500 due in 2013, bearing interest at 6.16%, and $20,000 due in 2008, bearing interest at 5.42%. Interest is payable monthly. Financing costs of $1,215 have been deferred and are amortized over the remaining terms of the related debt. Amortization expense of $163 has been recorded for the year ended December 31, 2006 (2005 – $163).

(c) In 2004, $90,000 of unsecured senior notes were issued by KEFL and guaranteed by the Partnership. The notes bear interest at 5.23% and mature on October 1, 2009. Interest is payable semi-annually. Financing costs of $568 have been deferred and are amortized over the term of the debt. Amortization expense of $114 has been recorded for the year ended December 31, 2006 (2005 – $114).

(d) A subsidiary of the Partnership has an unsecured revolving demand loan facility with a major Canadian chartered bank in the amount of $7,000, of which $7,000 was drawn as at December 31, 2006 (2005 – $3,000). Borrowings under the loan facility bear interest based on the lender's rates for Canadian prime commercial loans or Bankers' Acceptances rates. The weighted average interest rate for the year ended December 31, 2006 was 5.07% (2005 – 4.13%).

7. CONVERTIBLE DEBENTURES

In 2004, the Fund issued convertible unsecured subordinated debentures in the principal amount of $100,000. These debentures will mature on June 30, 2011 and are convertible into trust units of the Fund at the option of the holders at any time prior to maturity at a conversion price of $12.00 per unit. At December 31, 2006 $76,458 debentures had been converted to trust units (2005 – $69,287).

Financing costs consisting of an underwriters' commission of $4,000 and issuance costs of $332 have been deferred, and when there are no conversions, are being amortized over the term of the debt. Upon conversion of the debentures, the financing cost related to the principal amount of debt converted is adjusted and is recognized as a debit to unitholders' equity. As a result of conversions to date at December 31, 2006, $2,782 has been reclassified to unitholders' equity (2005 – $2,470). Amortization expense of $111 has been recorded for the year ended December 31, 2006 (2005 – $624)

The convertible debentures bear interest at 6.75% per annum, payable semi-annually in arrears on June 30 and December 31 each year. Interest expense of $1,776 has been accrued for the year ended December 31, 2006 (2005 – $2,958).

8. ASSET RETIREMENT OBLIGATION

The following table presents the reconciliation between the beginning and ending aggregate carrying amount of the obligation associated with the retirement of the Fund's facilities.

For the year ended December 31	**2006** **$**	2005 $
Asset retirement obligation, beginning of year	**27,776**	24,188
Liabilities acquired	**151**	744
Liabilities settled	**(160)**	(183)
Revisions in estimated cash flows	**4,509**	979
Accretion expense	**2,257**	2,048
Asset retirement obligation, end of year	**34,533**	27,776

The total undiscounted amount of cash flows required to settle the asset retirement obligations is $183,159 which has been discounted using a credit-adjusted risk-free rate of 7% (2005 – $168,150). The majority of these obligations are expected to be settled between 2018 and 2038. No assets have been legally restricted for settlement of the liability.

9. INCOME TAXES

The Fund is a unit trust for income tax purposes. As such, the Fund is only taxable on any taxable income not allocated to the unitholders. Each unitholder resident in Canada will be required to include in computing income for tax purposes for a particular taxation year the pro rata share of the Fund's income that was paid or payable in that year to the unitholder and that was deducted by the Fund in computing its income.

9. INCOME TAXES (continued)

The following is a reconciliation of income taxes, calculated at the combined federal and provincial income tax rates, to the income tax provision included in the consolidated statements of earnings.

	2006 $	2005 $
Earnings before tax and non-controlling interest	**66,443**	68,014
Income from the Fund distributed to unitholders	**(36,061)**	(42,653)
Income before taxes – operating subsidiaries	**30,382**	25,361
Income tax at statutory rate of 34.49% (2005 – 37.62%)	**10,479**	9,541
Non-deductible items excluded from income for tax purposes	**(142)**	2,083
Rate adjustments and changes in estimates	**(10,356)**	(2,467)
Benefit of long-term incentive plan previously not recorded	**(2,202)**	–
Benefit of non-capital losses previously not recorded	**(46)**	442
Resource allowance	**3**	(51)
Adjustments to tax pool balances	**(198)**	(3,554)
Other	**(198)**	(392)
Large corporation tax	**–**	1,028
	(2,660)	6,630
Classified as:		
Current	**4,382**	4,219
Future	**(7,042)**	2,411
Income tax expense	**(2,660)**	6,630

For income tax purposes, the subsidiaries of the Fund have non-capital losses carried forward of approximately $11,987 (2005 – $2,773) which are available to offset income of specific entities of the consolidated group in future periods. The benefit of these losses has been recorded at December 31, 2006.

The future income tax liability relates to the (taxable) deductible temporary differences in the carrying values and tax bases as follows:

As at December 31	2006 $	2005 $
Property, plant and equipment	**(71,611)**	(75,827)
Asset retirement obligation	**4,308**	4,104
Long-term incentive plan	**1,513**	-
Non-capital losses	**3,475**	–
Intangible assets	**(616)**	(956)
Other	**(2,493)**	213
Future income tax liability	**(65,424)**	(72,466)

The unrecorded future tax liability attributable to the Partnership at December 31, 2005 was $72,882 (2005 – $84,612).

10. UNITHOLDERS' CAPITAL

The Declaration of Trust provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, and represents an equal undivided beneficial interest in any distribution from the Fund and in the net assets of the Fund in the event of termination or winding-up of the Fund. All trust units are of the same class with equal rights and privileges.

The Declaration of Trust also provides for the issuance of an unlimited number of special trust units that can be used solely for providing voting rights to persons holding securities that are directly or indirectly exchangeable for units and that, by their terms, have voting rights in the Fund.

The trust units are redeemable at the holder's option at an amount equal to the lesser of: (i) 90% of the weighted average price per unit during the period of the last 10 trading days during which the units were traded on the Toronto Stock Exchange; and (ii) an amount equal to (a) the closing market price of the units; (b) an amount equal to the average of the highest and lowest prices of units on the date on which the units were tendered for redemption; or (c) the average of the last bid and ask prices if there was no trading on the date on which the units were tendered for redemption.

Redemptions are subject to a maximum of $50 cash redemptions in any particular month. Redemptions in excess of this amount will be paid by way of a distribution in specie of assets of the Fund that may include Commercial Trust Series 1 notes.

In 2005, the Fund instituted a Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP") that permits unitholders to reinvest cash distributions for additional units. This plan allows eligible participants an opportunity to reinvest distributions into trust units at a 3% discount to a weighted average market price, so long as units are issued from treasury under the DRIP. The Fund has the right to notify participants that units will be acquired in the market, in which case units will be purchased at the weighted average market price. Eligible unitholders can also make optional unit purchases under the optional unit purchase component of the plan at the weighted average market price.

Trust units issued and unitholders' capital

	Number of Units	$
Balance, January 1, 2005	**57,414,677**	**633,604**
Units issued on conversion of convertible debentures	2,586,968	30,135
Units issued pursuant to DRIP	88,223	1,598
Units issued pursuant to LTIP	35,325	577
Balance, December 31, 2005	**60,125,193**	**665,914**
Units issued on conversion of convertible debentures	597,563	6,859
Units issued pursuant to DRIP	207,997	4,252
Balance, December 31, 2006	**60,930,753**	**677,025**

Net earnings per unit

Basic per unit calculations for the years ended December 31, 2006 and 2005 were based on the weighted average number of units outstanding for the applicable year. Convertible debentures were in the money for the years ended December 31, 2006 and 2005 and attributed to the increase in diluted weighted average number of units for 2006 and 2005.

10. UNITHOLDERS' CAPITAL (continued)

Beginning in the second quarter of 2006, incentive awards have been excluded from the calculation of diluted weighted average number of units as units are delivered by acquiring them on the market rather than issuing them from treasury.

(thousands)	**2006**	2005
Weighted average number of units – basic	**60,604**	58,947
Net additional units if incentive awards vested	**-**	485
Additional units if debentures converted	**2,190**	3,643
Weighted average number of units – diluted	**62,794**	63,075

11. ACCUMULATED CASH DISTRIBUTIONS TO UNITHOLDERS

	$
Balance, January 1, 2005	**52,842**
Unitholders' distributions declared and paid	71,386
Unitholders' distributions declared	7,155
Balance, December 31, 2005	**131,383**
Unitholders' distributions declared and paid	79,354
Unitholders' distributions declared	7,251
Balance, December 31, 2006	**217,988**

12. COMPENSATION PLANS

The Long Term Incentive Plan (the "LTIP" or the "Plan") compensates officers, directors, key employees and consultants by delivering units of the Fund or paying cash in lieu of units. Participants in the LTIP are granted rights ("unit awards") to receive units of the Fund on specified dates in the future. The Plan permits the directors of KEML to authorize the grant of unit awards from time to time. Units are acquired in the marketplace under the plan.

The Plan consists of two types of unit awards, which are described below. Unit awards and the delivery of units under the Plan are accounted for in accordance with the intrinsic value method of accounting for stock-based compensation. The aggregate compensation cost recorded for the Plan was $3,017 for the year ended December 31, 2006 (2005 – $10,589).

During the year ended December 31, 2006, 161,731 units were purchased on the market at a cost of $3,351 and delivered to plan participants under the plan. In addition, the equivalent of 106,132 unit awards were settled in cash.

(a) Performance Unit Awards

Performance Unit Awards will vest 100% on the third anniversary of the effective date of each award, July 1, 2004, July 1, 2005 and July 1, 2006. The number of units to be delivered will be determined by the financial performance of the Fund over the three-year period. The number of units to be delivered will be calculated by multiplying the number of unit awards by an adjustment ratio and a payout multiplier. The adjustment ratio adjusts the number of units to be delivered to reflect the per unit cash distributions paid by the Fund to its unitholders during the term that the unit award is outstanding. The payout multiplier is based upon the actual three-year average annual cash distributions per unit of the Fund. The table below describes the relationship between the three-year average annual cash distribution per unit and the payout multiplier.

Three-year annual cash distributions per unit

	July 1, 2004 Grant	July 1, 2005 Grant	July 1, 2006 Grant	Payout Multiplier
	Less than 1.15	Less than 1.32	Less than 1.42	Nil
First range	1.15 – 1.22	1.32 – 1.39	1.42 - 1.51	50% – 99%
Second range	1.23 – 1.38	1.40 – 1.55	1.52 – 1.71	100% - 199%
Third range	1.39 and greater	1.56 and greater	1.72 and greater	200%

As of December 31, 2006, 529,867 Performance Unit Awards were outstanding (2005 – 478,172): 161,737 effective July 1, 2004, 197,330 effective July 1, 2005 and 170,800 effective July 1, 2006. The compensation cost recorded for these units for the year ended December 31, 2006 was $1,431 using the applicable closing market price of a unit of the Fund (2005 – $8,246).

(b) Time Vested Unit Awards ("Restricted Unit Awards")

Restricted Unit Awards will vest automatically, over a three-year period from the effective date of each award, July 1, 2004, July 1, 2005 and July 1, 2006 regardless of the performance of the Fund. The number of units to be delivered will be modified by an adjustment ratio which reflects the per unit distributions paid by the Fund to its unitholders during the term that the unit award is outstanding.

As of December 31, 2006, 98,735 Restricted Unit Awards were outstanding (2005 – 123,427): 26,049 effective July 1, 2004, 29,086 effective July 1, 2005 and 43,600 effective July 1, 2006. The compensation cost recorded for these units for the year ended December 31, 2006 was $1,586 using the applicable closing market price of a unit of the Fund (2005 – $2,343).

13. FINANCIAL INSTRUMENTS

Energy price risk management

Subsidiaries of the Fund enter into contracts to purchase and sell natural gas, NGLs and crude oil. These contracts are exposed to commodity price risk between the time contracted volumes are purchased and sold and currency exchange risk for those sales denominated in U.S. dollars. These risks are actively managed by using forward currency contracts and swaps, energy related forwards, swaps and options and by balancing physical and financial contracts in terms of volumes, timing of performance and delivery obligations. Management monitors the exposure to the above risks and regularly reviews its financial instrument activities and all outstanding positions.

A significant amount of electricity is consumed by the operating entities at their facilities. Due to the fixed fee nature of some service contracts in place with customers, these entities are unable to flow the cost of electricity to customers in all situations. In order to mitigate this exposure to fluctuations in the price of electricity, price swap agreements may be used.

Price swap agreements require payments to (or receipts from) counter parties based on the differential between fixed and variable prices for commodities. Forward currency exchange contracts require the exchange of currencies between counter-parties at previously agreed upon exchange rates.

The fair values of the derivatives designated as hedges are listed below and represent an estimate of the amount that the Fund would receive (pay) if these instruments were closed out at the end of the period.

2006	Carrying Amount $	Weighted Average Price	Notional Volume	Fair Value $
Natural gas:				
Price swaps *(maturing by March 31, 2007)*	**–**	**$7.78/GJ**	**90,000 GJs**	**(130)**
Electricity:				
Price swaps *(maturing by December 31, 2008)*	**–**	**$55/MWh**	**43,860 MWhs**	**1,031**
2005				
Natural gas:				
Price swaps	–	–	–	–
Electricity:				
Price swaps	–	–	–	–

Where the financial instrument is not designated as a hedge or does not meet the criteria for hedge accounting, it is recorded on the consolidated statement of financial position at its fair value, either as an asset or a liability under accounts receivable or accounts payable and accrued liabilities, respectively. Changes in the fair value of these financial instruments are recognized in earnings in the period in which they occur.

In 2006, Keyera realized and recorded $6.6 million of proceeds in Marketing revenue related to the settlement of financial instruments. A further $0.5 million of unrealized gains on financial contracts was recorded in Marketing revenue. The fair value of the financial instruments which do not qualify or have not been designated as hedges are listed below. The carrying amounts are recorded in accounts receivable and accounts payable, respectively.

2006	Carrying Amount $	Weighted Average Price	Notional Volume	Fair Value $
NGLs:				
Price swaps *(maturing between January 31, 2007 and March 30, 2007)*	**211**	**$72.25/Bbl**	**450,000 Bbls**	**211**
Currency:				
Forward contracts *(maturing between January 3, 2007 and January 26, 2007)*	**(287)**	**$1.1477/USD**	**US$16,350**	**(287)**
2005				
NGLs:				
Price swaps *(maturing by March 31, 2006)*	(280)	$69.06/Bbl	60,000 Bbls	(280)
Currency:				
Forward contracts *(maturing between January 5, 2006 and January 31, 2006)*	(60)	$1.1613/USD	US$13,000	(60)

The estimated fair value of all financial instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers.

Credit risk

The majority of accounts receivable are due from entities in the oil and gas industry and are subject to normal industry credit risks. Concentration of credit risk is mitigated by having a broad domestic and international customer base. The Fund evaluates and monitors the financial strength of its customers in accordance with its credit policy. At December 31, 2006, the accounts receivable from the two largest customers amounted to less than 1% of accounts receivable (2005 – less than 1%). Revenue from the two largest customers amounted to 11% of operating revenue in 2006 (2005 – 12%). With respect to counterparties for financial instruments used for economic hedging purposes, the credit risk is managed through dealing with recognized futures exchanges or investment grade financial institutions and by maintaining credit policies which significantly minimize overall counter party credit risk.

Interest rate risk

Fixed and floating rate debt are used to finance operations. The floating rate debt creates exposures to changes in interest payments as interest rates fluctuate. At December 31, 2006, fixed rate borrowings comprised 67% of total debt outstanding (2005 – 77%). The fair value of the senior fixed rate debt at December 31, 2006 was $224,457 (2005 – $222,074). The fair value of the Fund's unsecured convertible debentures at December 31, 2006 was $31,782 (2005 – $55,591).

13. FINANCIAL INSTRUMENTS (continued)

Fair value

The carrying values of cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities approximate their fair values because the instruments are near maturity or have no fixed repayment terms. The fair value of the bank credit facilities approximates fair value due to their floating rates of interest.

Foreign currency rate risk

The Gathering and Processing and NGL Infrastructure segments, where all sales and virtually all purchases are denominated in Canadian dollars, are not subject to foreign currency rate risk. In the Marketing business, approximately US$313,191 of sales were priced in U.S. dollars for the year ended December 31, 2006 (2005 – US$238,584). In 2006, the Fund realized and recorded $0.7 million of realized foreign currency loss in operating expenses. A further $0.8 million of unrealized foreign currency loss was also recorded in operating expenses.

14. COMMITMENTS AND CONTINGENCIES

The Fund, through its operating entities, is involved in various contractual agreements with a major oil and gas producer. The agreements range from one to twelve years and comprise the processing of the producer's natural gas and the purchase of its NGL production in the areas specified in the agreements. The purchase prices are based on current period market prices.

There are operating lease commitments relating to railway tank cars, vehicles, computer hardware, office space, terminal space and natural gas transportation. The estimated annual minimum operating lease rental payments from these commitments are as follows:

	$
2007	**8,480**
2008	**7,870**
2009	**5,176**
2010	**3,761**
2011	**2,410**
Thereafter	**3,500**
	31,197

There are legal actions for which the ultimate results cannot be ascertained at this time. Management does not expect the outcome of any of these proceedings to have a material effect on the financial position or results of operations.

15. SUPPLEMENTAL CASH FLOW INFORMATION

The 2005 amounts were reclassified to reflect the nature of the changes in non-cash working capital. As a result, changes in non-cash operating activities decreased by $7,909, changes in non-cash investing activities increased by $4,951 and changes in non-cash financing activities increased by $2,958.

Other cash flow information	**2006** **$**	2005 $
Interest paid	**18,486**	14,933
Taxes paid	**4,601**	4,024

16. SEGMENTED INFORMATION

The Fund has three reportable segments: Gathering and Processing, NGL Infrastructure and Marketing. Gathering and Processing includes natural gas gathering and processing. NGL Infrastructure includes NGL and crude oil processing, transportation, and storage. The Marketing business consists of marketing of NGLs, sulphur and crude oil. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. Intersegment sales and expenses are recorded at current market prices.

	Gathering and Processing $	NGL Infrastructure $	Marketing $	Corporate $	Total $
Year ended December 31, 2006					
Revenue	170,184	69,072	1,161,899	-	1,401,155
Inter-segment revenue	(3,448)	(29,184)	-	-	(32,632)
External revenue	166,736	39,888	1,161,899	-	1,368,523
Operating expenses	(96,558)	(23,956)	(1,134,677)	-	(1,255,191)
Inter-segment expenses	-	-	32,632	-	32,632
External operating expenses	(96,558)	(23,956)	(1,102,045)	-	(1,222,559)
	70,178	15,932	59,854	-	145,964
General and administrative, interest and other	-	-	-	(37,048)	(37,048)
Depreciation and amortization	(28,237)	(7,707)	(3,299)	(600)	(39,843)
Accretion expense	(1,950)	(297)	(10)	-	(2,257)
Impairment expense	(373)	-	-	-	(373)
Earnings (loss) before tax and non-controlling interest	39,618	7,928	56,545	(37,648)	66,443
Income tax recovery (expense)	-	(4,133)	(143)	6,936	2,660
Earnings (loss) before non-controlling interest	39,618	3,795	56,402	(30,712)	69,103
Identifiable assets	819,416	232,076	163,826	7,694	1,223,012
Capital expenditures	45,498	14,573	12,040	1,757	73,868

16. SEGMENTED INFORMATION (continued)

	Gathering and Processing $	NGL Infrastructure $	Marketing $	Corporate $	Total $
Year ended December 31, 2005					
Revenue	142,916	57,759	1,013,334	–	1,214,009
Inter-segment revenue	(3,642)	(22,800)	–	–	(26,442)
External revenue	139,274	34,959	1,013,334	–	1,187,567
Operating expenses	(67,469)	(24,296)	(972,704)	–	(1,064,469)
Inter-segment expenses	–	–	26,441	–	26,441
External operating expenses	(67,469)	(24,296)	(946,263)	–	(1,038,028)
	71,805	10,663	67,071	–	149,539
General and administrative, interest and other	–	–	–	(41,430)	(41,430)
Depreciation and amortization	(25,838)	(6,990)	(2,301)	(1,758)	(36,887)
Accretion expense	(1,784)	(264)	–	–	(2,048)
Impairment expense	(1,160)	–	–	–	(1,160)
Earnings (loss) before tax and non-controlling interest	43,023	3,409	64,770	(43,188)	68,014
Income tax (expense)	–	(5,297)	–	(1,333)	(6,630)
Earnings (loss) before non-controlling interest	43,023	(1,888)	64,770	(44,521)	61,384
Identifiable assets	794,792	222,708	184,878	15,782	1,218,160
Capital expenditures	43,122	8,761	–	987	52,870

	2006 **$**	2005 $
Marketing revenue derived from export sales to the U.S.	**84,577**	74,689
Property, plant and equipment located in the U.S.	**11,925**	–

17. SUBSEQUENT EVENT

The Government of Canada has announced a proposed tax on the income of publicly-traded Canadian income trusts and limited partnerships. As an existing income trust, the new tax will not apply to the Fund until January, 2011. The imposition of this tax will reduce the amount of cash that the Fund would otherwise have available for distribution after January 1, 2011.

Legislation to impose this tax has not been introduced and there is no assurance that the tax will be imposed. Substantive enactment of this legislation is expected to increase future income tax liabilities, and reduce future net income in the periods after substantive enactment.

Keyera Facility Capacities and Utilization Rates

NATURAL GAS PROCESSING FACILITIES

Facility	Ownership Interest *(%)*	License Capacity *(MMcf/d)*	Average Daily Throughput *(MMcf/d)*	Utilization Rate *(%)*
Rimbey	86	422	299	71
Strachan	86	275	144	52
Brazeau River	52	218	86	39
Chinchaga	100	148	38	26
Bigoray	90	85	28	33
Paddle River	87	81	16	20
Nordegg River	78	75	55	73
Gilby	78	71	36	51
Medicine River	24	64	35	55
Brazeau North	68	49	13	27
West Pembina	74	43	17	40
Caribou	100	65	37	70[1]
Greenstreet	100	25	6	24
Worsley	100	20	7	35
Tomahawk	68	16	1	6
North Star	87	6	1	8
Total		**1,663**	**819**	**49**[1]

[1] *Weighted average utilization rate for Caribou gas plant.*

NGL PROCESSING AND TRANSPORTATION

	Ownership Interest *(%)*	License Capacity *(bbls/d)*	Average Daily Throughput *(bbls/d)*	Utilization Rate *(%)*
NGL Processing				
Fort Saskatchewan *(Keyera)*	77	30,200	28,353	94
Rimbey Gas Plant	86	31,500	15,363	49
Gilby Gas Plant	78	3,200	1,665	52
Fort Saskatchewan				
(Dow NGL processing)	18	30,000	22,458	75
(Dow De-ethanizer)	10	69,200	53,546	77
NGL Pipelines				
Fort Saskatchewan *(Keyera)*	77	210,000	122,521	58
Rimbey Pipe Line	89	45,000	36,809	82

NGL STORAGE FACILITIES

	Ownership Interest *(%)*	Gross Capacity *(bbls)*	Net Capacity *(bbls)*
Fort Saskatchewan *(Keyera)*	77	8,602,000	6,623,500
Fort Saskatchewan *(Dow)*	18	2,000,000	360,000

Glossary of Terms

acid gas	hydrogen sulphide or carbon dioxide or a combination thereof
acid gas injection	the injection of acid gas into a suitable underground geological formation
bbls and bbls/d	barrels and barrels per day
bitumen	a viscous, tar-like oil that is extracted through non-conventional production methods such as mining or in situ recovery. Bitumen requires upgrading or blending to make it transportable by pipeline and usable by conventional refineries.
butane	a natural gas liquid (NGL) with the molecular formula C_4H_{10}
condensate	a natural gas liquid (NGL) consisting primarily of pentanes and heavier liquids
diluent	light liquid petroleum products, such as condensate, that are blended with bitumen and heavy oil so they can flow through the pipelines
in situ	"in place". If an oil sands deposit is too deep to mine from the surface, in situ recovery methods such as steam injection or through horizontal or vertical wells are required.
MMcf/d	million cubic feet per day
NGL or NGLs	natural gas liquids, consisting of any one or a combination of propane, butane and condensate
NGL mix	NGLs that have been separated from the raw gas but have not yet been processed into propane, butane or condensate
propane	a natural gas liquid (NGL) with the molecular formula C_3H_8
raw gas	natural gas before it has been subjected to any processing that may be required for it to become suitable for sale
sales gas	natural gas that has been treated in a natural gas processing facility and is suitable for sale
sour gas	natural gas containing more than one percent hydrogen sulphide
sulphur	a yellow mineral extracted from natural gas
sweet gas	natural gas that contains no hydrogen sulphide or less than one percent hydrogen sulphide when produced

Fund Information

BOARD OF DIRECTORS

E. Peter Lougheed (1)(3)
Counsel, Bennett Jones LLP
Calgary, Alberta

Jim V. Bertram (4)
President and Chief Executive Officer
Keyera Energy Management Ltd.
Calgary, Alberta

Robert B. Catell
Chairman and Chief Executive Officer
KeySpan Corporation
New York, New York

Michael B.C. Davies (2)
Principal, Davies & Co.
Banff, Alberta

Nancy M. Laird (3)(4)
Corporate Director
Calgary, Alberta

H. Neil Nichols (2)(3)
Management Consultant
Mississauga, Ontario

William R. Stedman (3)(4)
Chairman and
Chief Executive Officer
ENTx Capital Corporation
Calgary, Alberta

Wesley R. Twiss (2)
Corporate Director
Calgary, Alberta

OFFICERS

Jim V. Bertram
President and Chief Executive Officer

David G. Smith
Executive Vice President,
Chief Financial Officer
and Corporate Secretary

Marzio Isotti
Vice President,
West Central Region

Steven B. Kroeker
Vice President,
Corporate Development

Bradley W. Lock
Vice President, Engineering
and Operational Services

David A. Sentes
Vice President,
Comptroller

K. Jamie Urquhart
Vice President,
Foothills Region

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STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbols KEY.UN; KEY.DB

CORPORATE TRUSTEE and Transfer Agent

Computershare Trust
Company of Canada
Calgary, Alberta

AUDITORS

Deloitte & Touche LLP
Calgary, Alberta

LEGAL COUNSEL

Macleod Dixon LLP
Calgary, Alberta

ANNUAL MEETING OF UNITHOLDERS

June 6, 2007, 9:30 a.m.
Kensington Room
Marriott Hotel
110 – 9th Avenue S.E.
Calgary, Alberta

INVESTOR RELATIONS

John Cobb
Director, Investor Relations

Avery Reiter
Investor Relations Advisor

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Email: ir@keyera.com

STABILITY RATING

Standard & Poor's SR-3

2006 TRADING SUMMARY

Units Outstanding (December 31):
60.9 million

Total Units Traded:
44.4 million

Total Value Traded:
$907.9 million

Average Daily Trading Volume:
176,756 units

Trading Prices:
High: $24.75
Low: $15.51
Close (December 31): $16.64

(1) *Chairman*
(2) *Member of the Audit Committee*
(3) *Member of the Compensation and Governance Committee*
(4) *Member of the Health, Safety and Environment Committee*

KEYERA

www.keyera.com

END