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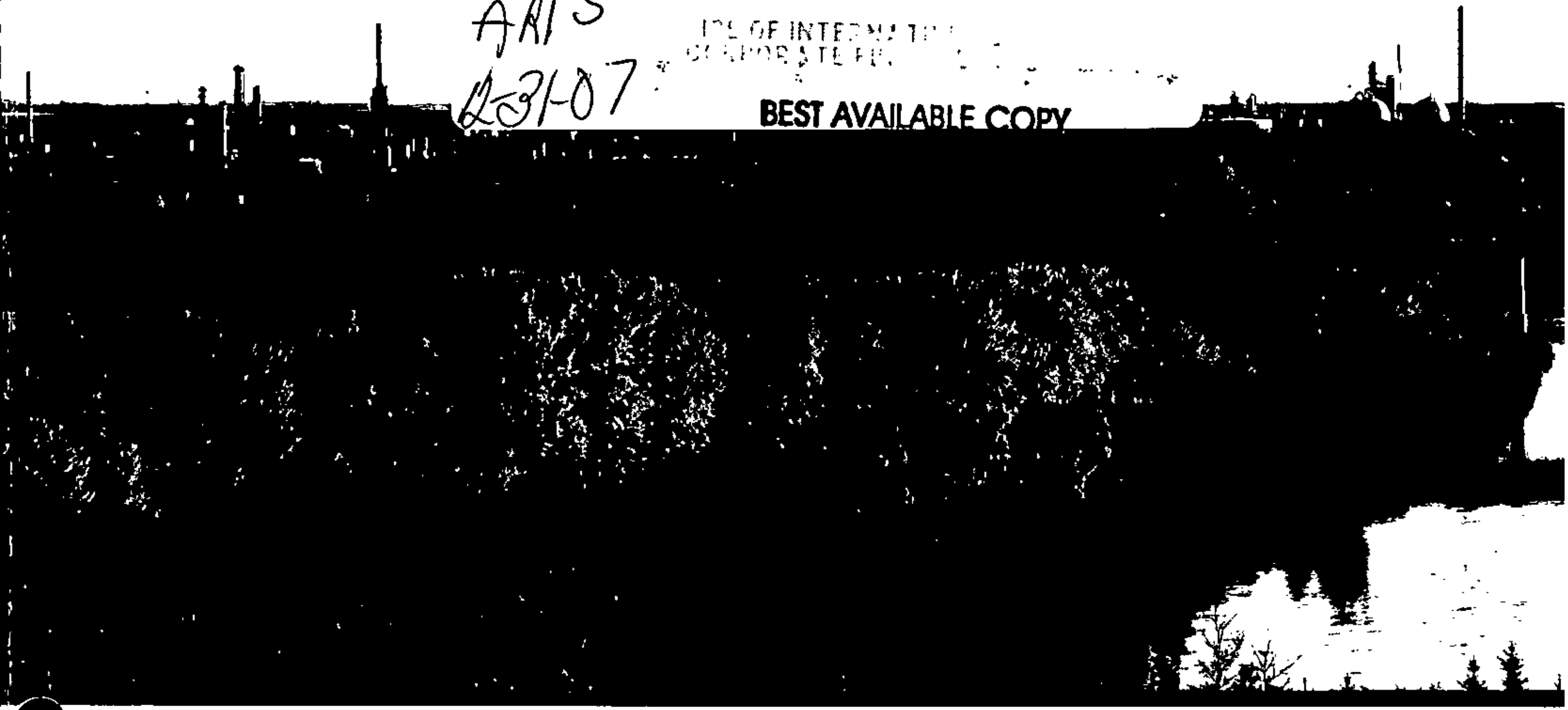


2007 Summary Annual Report

KEYERA

Ahead of the Curve

Investing for long-term value

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; processing, transportation and storage of natural gas liquids (NGLs) and crude oil; and NGL marketing and crude oil midstream services.

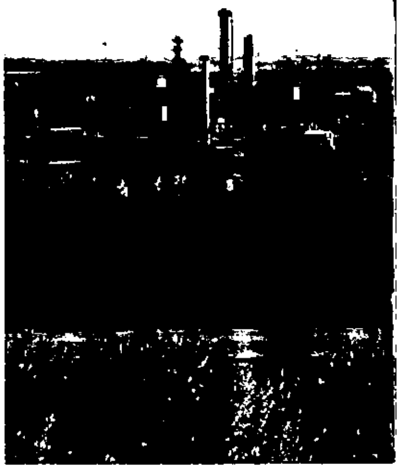
Our gathering and processing facilities are strategically located in natural gas production areas on the western side of the Western Canada Sedimentary Basin. Keyera's NGL and crude oil infrastructure includes pipelines, terminals, processing plants and storage facilities in Edmonton and Fort Saskatchewan,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

Notice to Readers

This Summary Annual Report contains forward looking information, which is based on management's current beliefs and assumptions. Actual events or results may differ materially. For further information, please refer to the advisories on page 38.

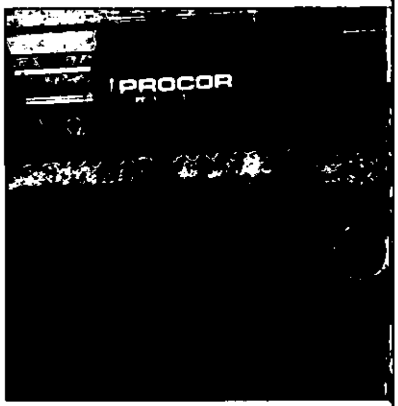
We encourage you to read our 2007 Financial Report, which contains Management's Discussion and Analysis and audited Consolidated Financial Statements and Notes. You can view these documents online at **www.keyera.com** or call us toll free at **1-888-699-4853** to obtain a copy.

Inside



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

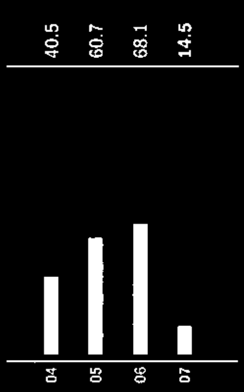
KEYERA



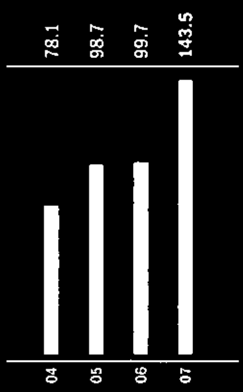
About the cover: Located in Alberta's Industrial Heartland alongside the North Saskatchewan River, Keyera's Fort Saskatchewan NGL fractionation and storage facility (top and centre photos) is well positioned to provide services to the evolving oil sands sector in Alberta. Keyera's infrastructure (like the Rimbey gas plant rail terminal shown in the bottom photo) is a key element in the success of our NGL marketing business.

Financial Highlights

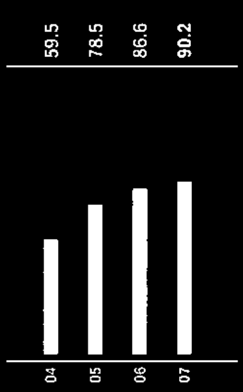
	2007	2006	2005	2004[2]
Revenues ($ millions)	1,479.1	1,368.5	1,187.6	937.4
Net earnings ($ millions)	14.5	68.1	60.7	40.5
Capital expenditures ($ millions)	32.0	73.9	52.9	29.8
Distributable cash flow[1] ($ millions)	143.5	99.7	98.7	78.1
Per unit ($)	2.35	1.65	1.67	1.50
Distributions to unitholders ($ millions)	90.2	86.6	78.5	59.5
Per unit ($)	1.48	1.43	1.33	1.14



Net Earnings
($ millions)



Distributable Cash Flow[1]
($ millions)



Distributions to Unitholders
($ millions)

Ahead of the curve reflects Keyera's entrepreneurial spirit. It reflects a proactive approach to operating our assets, anticipating the needs of our customers, capturing new opportunities, managing risks and growing our business. From regular, preventative maintenance of our facilities to emergency response planning, from projects that support producer initiatives to health, safety and environmental stewardship, Keyera is **Ahead of the curve**.

---

[1] See Note Regarding Non-GAAP Financial Measures on page 38. Distributable cash flow is not a standard measure under Canadian generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures reported by other entities. The most comparable GAAP measure to distributable cash flow is cash flow from operating activities. A reconciliation between distributable cash flow and cash flow from operating activities can be found on page 22 of Keyera's 2007 Financial Report.

[2] 2004 reflects Keyera Energy Partnership results and is included for comparison purposes. 2004 distributable cash flow is shown before deducting Fund expenses.

Keyera at a glance

We operate one of the largest natural gas midstream businesses in Canada. Our businesses are integrated and extend from the wellhead to the customer. The many services we provide are grouped into three business lines: Gathering and Processing; NGL Infrastructure; and NGL Marketing and Crude Oil Midstream.

Products and Services

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. Often, raw gas needs to be compressed to enter 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	Applying physical and chemical processes, we separate commercially valuable products, such as sales gas and natural gas liquids (NGLs) from the raw gas. Impurities, such as water, hydrogen sulphide and carbon dioxide, are removed and disposed of. Keyera charges customers a fee for these services.
NGL Processing	We separate the NGL mix recovered from the raw gas 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.

Business Lines

Strengths

Gathering and Processing

- 15 gas plants with gross capacity of 1.7 billion cubic feet per day
- Strategically located in the western part of the Western Canada Sedimentary Basin
- Broad capture areas and high barriers to entry
- Available unutilized capacity to accommodate additional volumes of raw gas
- Flexibility to process sour gas and extract NGLs
- Expertise in safe operation of large, sour gas facilities

NGL Infrastructure

- 4 NGL processing plants with net capacity of 65,000 barrels per day
- Strategically located in the Edmonton/Fort Saskatchewan area, a major North American energy hub
- 8.9 million barrels of storage capacity and 12 truck/rail terminals to support the NGL and oil sands sectors
- Logistics expertise and flexibility to receive and deliver NGL products into the Fort Saskatchewan energy hub
- Strategic undeveloped land for future growth

NGL Marketing and Crude Oil Midstream

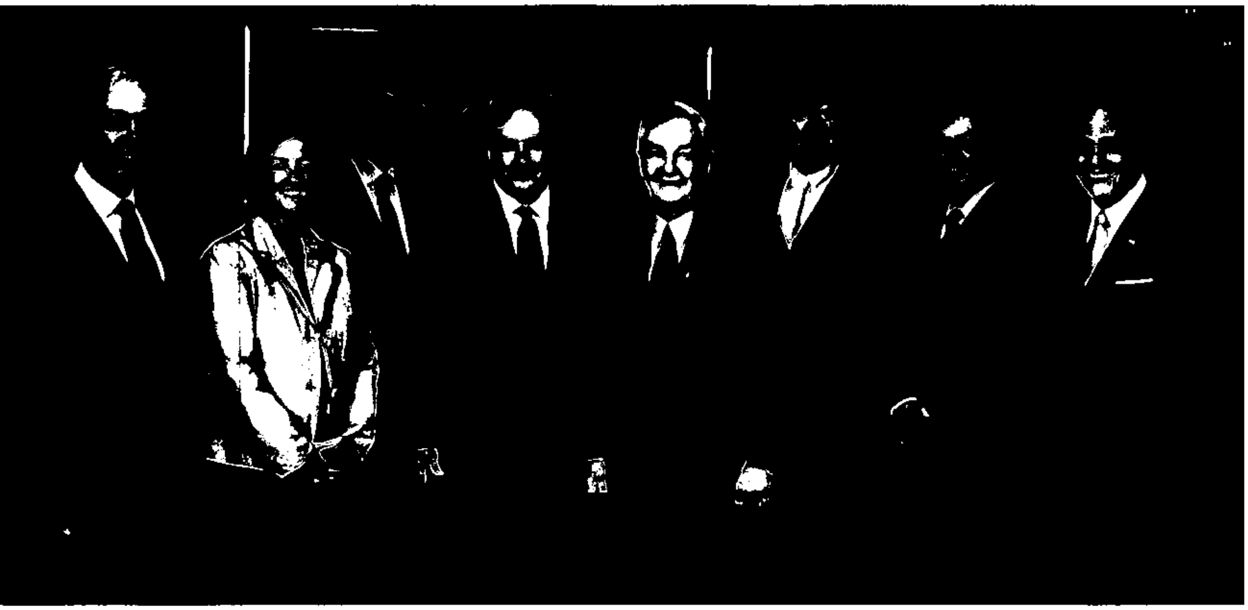
- Priority access to key fractionation, storage, pipeline, logistics and transportation infrastructure
- Integrated with Keyera's gathering and processing and NGL infrastructure assets, allowing us to enhance value throughout the midstream value chain
- Fleet of 600 railcars
- Geographic and customer diversity
- Logistics expertise across niche markets

Significant new business opportunities stem from having strategically located, interconnected infrastructure. Keyera is well positioned to benefit from future growth in the oil sands as well as ongoing natural gas activity around our plants.

NGL Transportation and Storage	Propane, butane and condensate are delivered to end-use markets by pipeline, truck or rail from loading terminals located at our processing and storage facilities. We also store product in our underground storage caverns for future processing or sale. Keyera charges customers a fee for these services.
NGL Marketing and Crude Oil Midstream	We purchase NGLs from about 200 natural gas producers and sell to more than 100 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.

Drivers	Opportunities
- Continued demand for western Canadian natural gas throughout North America - Ongoing drilling around our gas plants and gathering systems - Fiscal regime and economics that support continued natural gas producer activity - Attractive geology adjacent to our facilities - Advancements in drilling technology that enhance producer economics - Industry focus on cost structure improvements through facilities efficiencies	- Expanding plants and gathering systems to capture production from new areas - Modifying plants to create new sources of cash flow and meet the growing demand for raw gas processing - Pursuing acquisitions of existing gathering systems and processing plants - Encouraging plant consolidations as producers look to minimize capital and operating costs
- Continued development of liquids-rich natural gas in western Canada - Ongoing development of Alberta's oil sands - Evolution of the Edmonton/Fort Saskatchewan area as a key energy hub - Bitumen upgraders to be constructed in the Industrial Heartland - Demand for diluent to transport bitumen from the oil sands to upgrading facilities for conversion into synthetic crude oil	- Expanding our processing, transportation and storage facilities at Edmonton and Fort Saskatchewan - Providing additional processing, transportation, storage, blending and logistics services - Acquiring additional strategic infrastructure to support oil sands development - Increasing the number of connections to pipelines and facilities in the Edmonton/Fort Saskatchewan area
- Access to NGL supply – propane, butane and condensate - Capability to process, transport and deliver products to customers when they need it - Storage capacity for inventory to meet seasonal winter demand - Market knowledge and logistics expertise	- Importing additional condensate into Alberta to meet the growing diluent demand - Diversifying sources of NGL supply - Acquiring complementary infrastructure to support marketing efforts in the United States - Utilizing expanded Fort Saskatchewan storage capacity to enhance marketing margins

Board of Directors



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

Our business performance is linked to values that demand respect for people, communities and the environment. Keyera balances economic integrity, environmental stewardship and social responsibility, all of which are essential to our success.

Chairman's Message

> Keyera has proven its ability to deliver impressive results and seize new opportunities in a difficult business environment. With a clear vision for the business and a proven strategy, I am confident that Keyera will continue to find many opportunities for growth in the years ahead.

Looking back over the past year, it is clear that 2007 was a year of both challenge and opportunity for Keyera. The challenges appeared on many fronts, including fiscal and regulatory changes relating to taxation, royalties and the environment. These came at a time when weak natural gas prices and high costs were creating a slowdown in natural gas drilling. While these challenges are continuing to test organizations in the energy industry and beyond, Keyera has proven its ability to deliver impressive results and seize new opportunities in a difficult business environment. With three business lines and an increasing exposure to the growing oil sands sector in Alberta, Keyera is diversifying its sources of cash flow and positioning itself for continued future growth.

Keyera's success is the result of the consistent application of our long term growth, investment and risk management strategies, together with the strength of our people and the strategic location of our assets. Building on this solid foundation, Keyera delivered outstanding results in 2007 for the benefit of all of our stakeholders – investors, customers, partners, employees and communities.

In addition to our strong financial performance, I am extremely proud of our track record as an engaged and responsible corporate citizen. Keyera has fostered a culture that encourages an entrepreneurial approach to business, values teamwork, and places a premium on respect for people, communities and the environment. Throughout our proud history of operations in Alberta, Keyera has remained committed to these principles, and we continue to believe that they are an important dimension of our long-term success.

Keyera also recognizes the importance of upholding high standards of corporate governance. Your Board benefits greatly in the performance of its governance and oversight role from the unique perspectives and expertise offered by each director, as well as from ongoing, open dialogue with the management team.

With a clear vision for the business and a proven strategy, I am confident that Keyera will continue to find many opportunities for growth in the years ahead. I commend the Keyera team for their work in developing this vision and for providing the leadership necessary to keep Keyera ahead of the curve.

As a director and a unitholder, I am proud to continue to serve you.

On behalf of the Board of Directors,

E. Peter Lougheed
Chairman of the Board

February 26, 2008

2007 Report Card

We have a clear vision for our business: to deliver steady value growth built around sustainable, competitive energy facilities. Our three-phased growth strategy is anchored by our commitment to maintain a conservative capital structure. For nearly a decade, our focused strategic direction has remained consistent. Our results speak for themselves.

Strategies	2007 Results
Increase throughputs at our plants	» Achieved record throughput, 3% higher than 2006 » Increased sour gas processing utilization at three gas plants in the Pembina region » Increased throughput by 27% at the Caribou gas plant » Achieved higher NGL storage utilization at Keyera's Fort Saskatchewan facility » Increased sulphur handling at the Strachan gas plant » Increased condensate volumes offloaded at the Edmonton terminal
Pursue expansion and optimization opportunities	» Extended the Caribou North Gas Gathering System » Constructed a condensate truck loading rack at the Rimbey gas plant » Initiated a storage expansion program at the Fort Saskatchewan facility and began detailed engineering and site preparation » Acquired use of a pipeline to connect the Edmonton and Fort Saskatchewan areas » Began work on an expansion of the truck loading rack at the Fort Saskatchewan facility » Completed preliminary plant modifications and tie-ins to prepare for ethane extraction at the Rimbey gas plant
Selectively pursue acquisitions	» Increased our ownership of the Rimbey Pipeline to 100% » Increased our ownership in the Easyford oil battery to just over 25% » Purchased a pipeline system and plant site north of the Caribou gas plant » Acquired a pipeline lateral to extend Keyera's gathering pipelines in the Pembina area of Alberta
Maintain conservative capital structure	» Completed a private placement of $120 million of long-term unsecured senior notes at an aggregate interest rate of just over 6% » Maintained a net debt (including debentures) to cash flow ratio of 1.8 times in 2007 » Extended $150 million bank credit facility, which was undrawn at year-end

President's Message

President & CEO Jim Bertram provides his perspective on a wide range of topics.

In 2007, Keyera once again generated strong financial and operating results. Our focused strategy, well-located plants, and creative business development initiatives have allowed us to prosper in a year of industry uncertainty and change.

Jim, how do you feel about Keyera's performance in 2007?

I am extremely pleased with Keyera's performance. In 2007, Keyera delivered exceptional financial results, with strong contributions from each of our three business segments. Cash flow from operating activities reached a record $119.8 million. Distributable cash flow for the year was $143.5 million, or $2.35 per unit, the highest in our history. Distributions to unitholders totaled $1.48 per unit, resulting in a payout ratio of 63%.

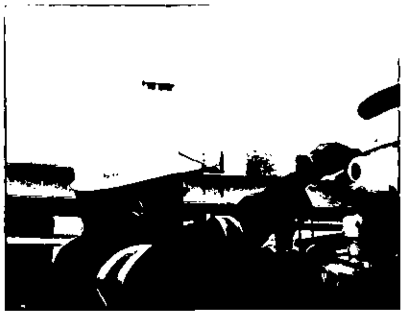
We continue to focus on providing our unitholders with sustainable growth in cash distributions. In February 2008, we increased our monthly distribution to $0.135 per unit, the sixth distribution increase in five years. This represents a 49% increase since the Fund's inception in 2003 and a compound annual growth rate of 8%.

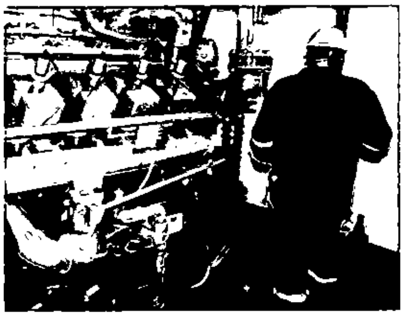
How were you able to deliver these results?

All three of our business lines delivered strong results in 2007. Throughput at our processing facilities was the highest in our history. We achieved record results in our NGL infrastructure business as a result of our increased focus on the oil sands sector. Our NGL marketing and crude oil midstream business had a very good year as well, with strong markets for each of our products.

Why didn't lower natural gas prices hurt your business in 2007?

Generally speaking, our business is only indirectly exposed to natural gas prices. Our gathering and processing business generates revenues on a fee-for-service basis that is not based on natural gas prices. Although lower gas prices were a factor in the slowdown of natural gas drilling experienced in western Canada in 2007, to date our gathering and processing business has benefited from ongoing producer activity around our facilities. In fact, throughput at our gas processing plants increased in 2007 to 843 million cubic feet per day, the highest in our history and 3% higher than last year.





Keyera facilities at Fort Saskatchewan and Edmonton are well positioned to provide diluent products, such as condensate, and related services to oil sands producers.

How can you have record throughput levels at your plants when drilling activity declined in 2007?

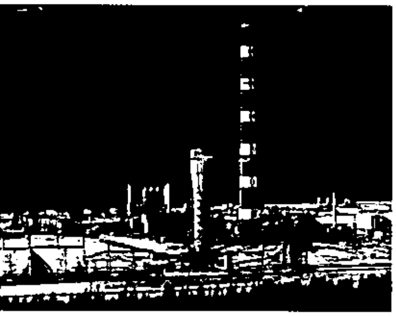
In a downturn, producers become more selective when choosing drilling locations and look for targets with good geology and attractive economics, such as those found west of the Fifth Meridian, where most of Keyera's facilities are located. In these areas, the land is relatively underdeveloped and the geology is highly prospective with multiple productive zones and liquids-rich gas. Producers also prefer to drill close to existing pipeline infrastructure to be able to tie in their production quickly. All of these factors favour the lands around most of our facilities.

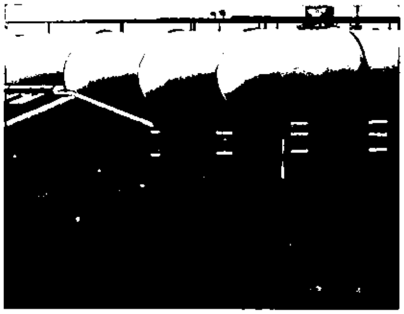
In what areas are you seeing the most promising producer activity?

Three of the most active producer areas are around our Caribou gas plant in northeastern British Columbia, in the Pembina region of Alberta and in the Foothills front region of Alberta – between our Strachan and Brazeau River gas plants. In each of these areas, we have partnered with the producers in various ways to connect their production quickly to Keyera infrastructure – a mutual benefit.

One of your key strategies involves positioning your assets in the Fort Saskatchewan area to meet the demand for oil sands related services. How are you doing this?

Our facilities and land position in the area are ideally located and we see enormous potential to provide ancillary products and services to the oil sands sector over the next several decades. With the growing demand for condensate for use as diluent, we have begun to expand our services through the construction of additional storage capacity, connecting our facilities to diluent pipelines in the area and enhancing our rail and truck terminalling services. These initiatives enhance our competitive advantage in the area and are already contributing to our cash flow.





To prepare for the future, we are expanding our underground storage capacity in Fort Saskatchewan and anticipate spending about $13 million in 2008 on the first of a four-cavern program. When all four caverns are complete, our storage capacity at this facility will increase by a third to 11.9 million barrels. In addition, we are adding a fourth pipeline between our Edmonton terminal and Fort Saskatchewan NGL facilities and expanding the truck terminal at our Fort Saskatchewan facility, both of which will significantly enhance our operational flexibility.

Regardless of our organizational structure, we believe we have the ability to adapt to the ever changing political and business landscape.

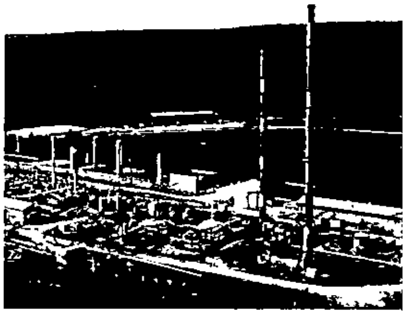
With taxation of income trust distributions set to take effect on January 1, 2011, do you plan to change your corporate structure?

We have always said that Keyera is ideally suited to be an income trust, given our long life assets, stable cash flows and strong competitive position, as well as the barriers to entry in all three of our business lines. Our performance over the last five years supports this view. At this time, we believe we could continue as an income trust beyond 2011, as the income tax payable by trusts and corporations will be similar when the new taxes take effect. However, there are a number of factors to weigh when considering the best legal structure. We are monitoring these factors and evaluating our options in order to arrive at a decision that we believe will be best for Keyera and our unitholders.

Regardless of our organizational structure, we believe we have the ability to adapt to the ever changing political and business landscape, thanks in part to our customer-focused business philosophy, our highly skilled team and our strategic assets.

What impact will Alberta's recently announced royalty changes have on Keyera when the new rates take effect in 2009?

While Keyera does not pay royalties, as a service provider we rely on natural gas producers for our throughput volumes. The royalty changes announced in 2007 have added uncertainty to the oil and gas industry and have the potential to slow down drilling activity in the province. Thanks to the strategic location of Keyera's facilities, to date we have not been affected by drilling slowdowns. We are also encouraged by the Alberta Government's acknowledgement that deep gas drilling is critical to future natural gas development in the province and by its intention to review the unintended consequences of the new royalty program, particularly with respect to deep gas drilling.



What strategies does Keyera have in place to deal with new regulations on greenhouse gas emissions?

Keyera has a long track record of implementing sound, environmentally responsible projects, ranging from acid gas injection to waste heat recovery initiatives. We are actively engaged in complying with new greenhouse gas emission rules implemented in Alberta in 2007. As well, we try to take a proactive approach, looking for new opportunities to achieve greenhouse gas reductions.

We believe successful implementation of our strategic growth initiatives will allow us to build on the competitive advantages we currently enjoy in each of our operating segments, while allowing us to diversify our business.

What are your plans for 2008?

The scope and breadth of our plants and facilities provides us with an extensive portfolio of internal growth opportunities. In 2007, we invested $30.6 million of growth capital on projects with significant scale and growth potential. In 2008, we anticipate that our growth capital spending will be between $80 and $100 million. Assuming the business environment remains similar to the past several years, this level of spending may be sustainable for several years.

In 2008, in addition to the projects in Fort Saskatchewan, we recently began construction of a 24-kilometre gathering pipeline extension at our Caribou plant. We are awaiting regulatory approval of our proposed $26 million ethane extraction project at the Rimbey gas plant. As well, we will continue to work to increase plant utilization by building pipelines, adding compression and modifying existing facilities.

Where do you see your business going in the longer term?

Our plan going forward is to continue to build on our proven strategy. I am very pleased with what we have accomplished to date and excited about the opportunities I see ahead for Keyera. Over the last four years, we have diversified our business, found new ways to generate cash flow from our existing assets and significantly increased our opportunities to service the developing oil sands sector. We have expanded our business and have entered new commercial business areas. All the while, we have applied a clear strategy in a disciplined manner, applying a business model that utilizes our strategically positioned assets to generate cash flow along the value chain.

Overall, our business should be able to perform well through the natural gas cycles. We believe that demand for natural gas will increase in North America and that the Western Canada Sedimentary Basin will remain a key source of supply. As a result, we anticipate continued drilling activity in western Canada, particularly on the western side of the basin where most of our facilities are located.

As our business diversifies, our reliance on any one sector of the oil and gas business lessens. Our NGL infrastructure and marketing businesses are increasingly leveraged to activity in the oil sands sector as we take advantage of opportunities associated with the growth in oil sands development expected over the next 10 to 20 years.

Our achievements are a result of the commitment, dedication and vision of our people and the relationships they have built with our customers, suppliers, communities and unitholders. I take great pride in thanking all of our employees for their hard work this year and for the contributions they have made in making this year the best in Keyera's history. I look forward to continuing to work with this enthusiastic team as we build on our record of success in the years to come.

Jim Bertram

Jim V. Bertram
President and Chief Executive Officer

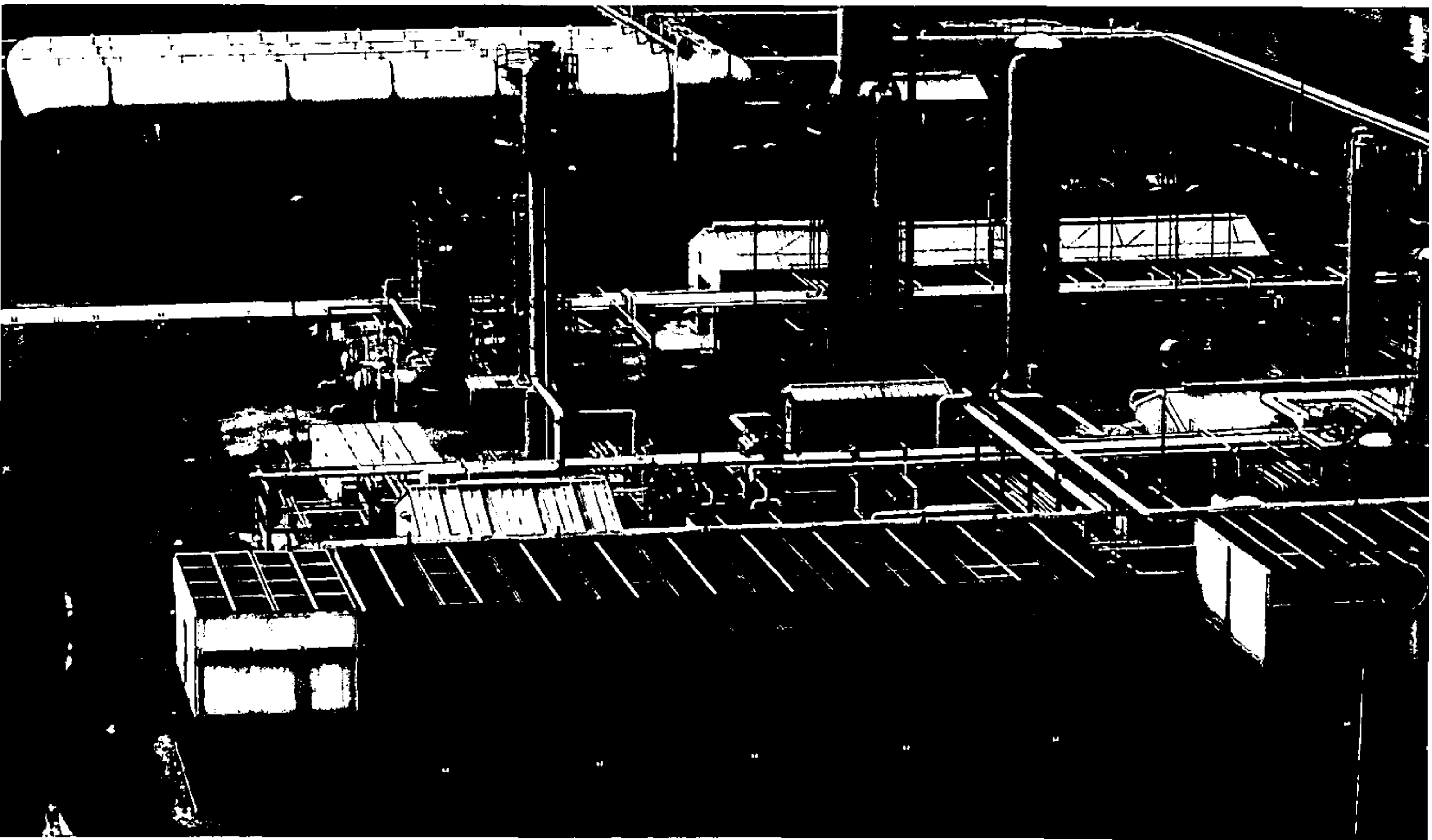
February 26, 2008

Keyera Management Team

Top row, left to right:
Jim V. Bertram
Bradley W. Lock
David A. Sentes

Bottom row, left to right:
Steven B. Kroeker
David G. Smith
Marzio Isotti

The consistent execution of our strategy has translated into a solid track record of profitability and growth for our unitholders that we continue to build on.



As one of the largest, independent midstream operators in western Canada, Keyera is well positioned to provide products and services to natural gas and oil sands producers over the coming decades. Significant new business opportunities will stem from our strategically located, interconnected infrastructure.

Growth Projects and Strategic Opportunities

Building a diversified portfolio for sustainable growth

The size, diversity and breadth of our infrastructure assets generate numerous growth opportunities in all three of our business lines. Over the last five years, Keyera has significantly grown cash flow and distributions by identifying and capturing opportunities tied to natural gas and NGL development. To build a diversified portfolio for long-term, sustainable growth, Keyera is also pursuing infrastructure opportunities tied to oil sands development. Many of these opportunities allow us to expand the range of products and services in our NGL marketing and crude oil midstream businesses, providing further diversification.

Growth projects west of the Fifth Meridian – focused on natural gas

We believe the future of natural gas in the Western Canada Sedimentary Basin lies west of the Fifth Meridian, where the lands are relatively under developed and wells drilled are often deeper, with multiple geological zones of interest. The strategic location of our gathering and processing facilities provides opportunities for plant and pipeline expansions. In today's business environment, natural gas producers are becoming more selective when choosing drilling locations, choosing targets with more attractive economics, located close to existing infrastructure. With restricted cash flows, producers are more likely to look to midstream companies, like Keyera, to develop new surface infrastructure. We have a number of expansion and optimization projects currently underway and additional opportunities are being evaluated to support continued producer activity around our plants.

Growth projects in Alberta's Industrial Heartland – focused on oil sands development

Our interconnected facilities in the Edmonton/Fort Saskatchewan region allow us to fractionate, store, transport and deliver NGL products into the majority of the pipelines, petrochemical plants and storage facilities in the Industrial Heartland around Fort Saskatchewan. This region is expected to become the heart of oil sands upgrading in Alberta. As one of the largest providers of storage, terminalling and other pipeline and logistics services in the region, as well as one of the largest suppliers of condensate for use as diluent, our assets and marketing expertise have created a significant competitive advantage. We expect demand for our services will continue to grow as bitumen production increases over the next decade, and we are pursuing several infrastructure projects to position Keyera for this growth.

Assets that support the oil sands

Keyera's significant NGL fractionation, storage, rail and truck terminals, and pipeline connections in the Edmonton/Fort Saskatchewan area are uniquely positioned to provide products and services to the growing oil sands sector in Alberta.

World scale resource

With proven reserves of 174 billion barrels, Alberta's oil sands rank second only to Saudi Arabia in reserves. Resource companies have acquired large land positions and begun pilot projects to validate the extraction process and resolve technological problems associated with in situ recovery. Today – and over the next decade – oil sands producers are moving into commercial development and bitumen production is expected to increase significantly.

Bitumen production expected to grow

Industry forecasts are that producers will spend over $100 billion on new oil sands projects over the next 10 to 20 years to grow bitumen production by as much as 4 million barrels per day. Because of its viscosity, bitumen must be blended with a lighter product, referred to as diluent, to enable it to flow via pipeline to upgraders in Fort Saskatchewan and elsewhere in North America for conversion into synthetic crude oil. Up to 500,000 barrels per day of incremental diluent may be required. Condensate, a very light crude oil often extracted from liquids-rich natural gas, is the preferred diluent.

Fort Saskatchewan: Alberta's Industrial Heartland

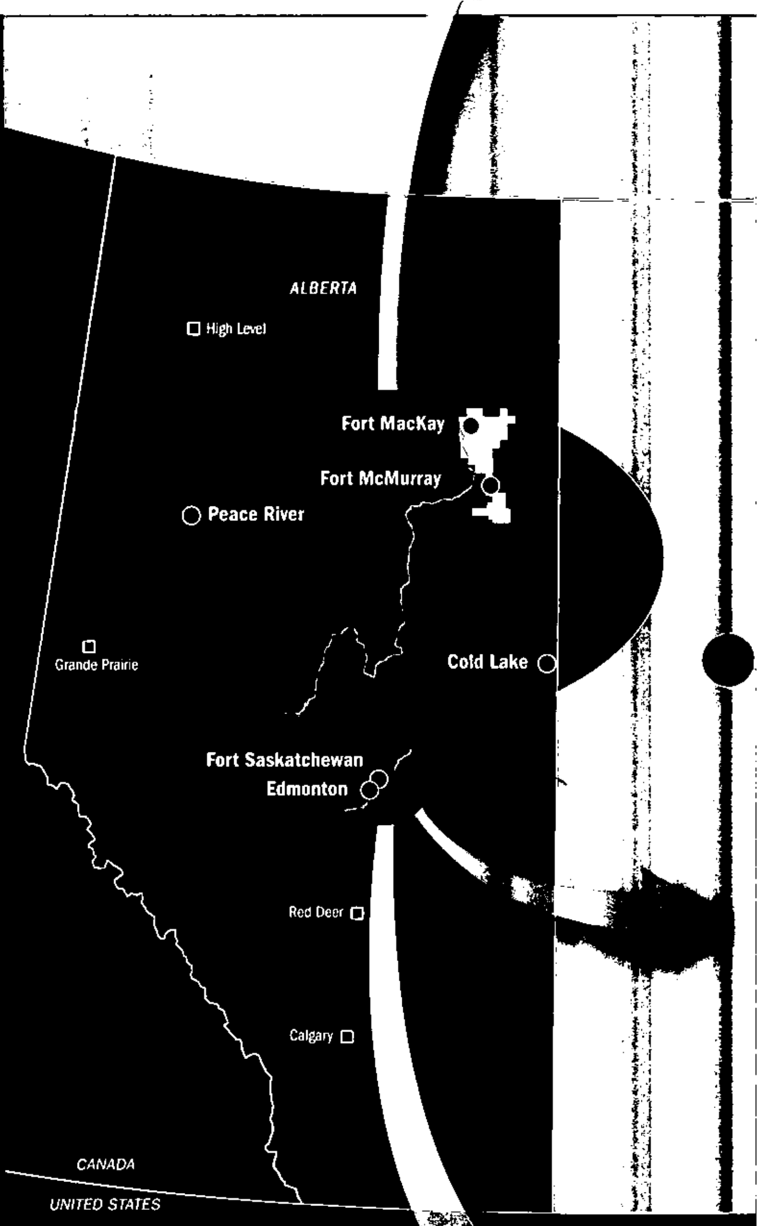
Indications are that most of the bitumen upgrading in Canada from in situ production will occur in the Industrial Heartland around Fort Saskatchewan. Eight upgraders are either being built or are in various stages of planning. The majority of bitumen, diluent and synthetic crude oil pipelines will either terminate or pass through the Industrial Heartland. The volume of products required and the associated logistics, storage and handling services present opportunities for Keyera.

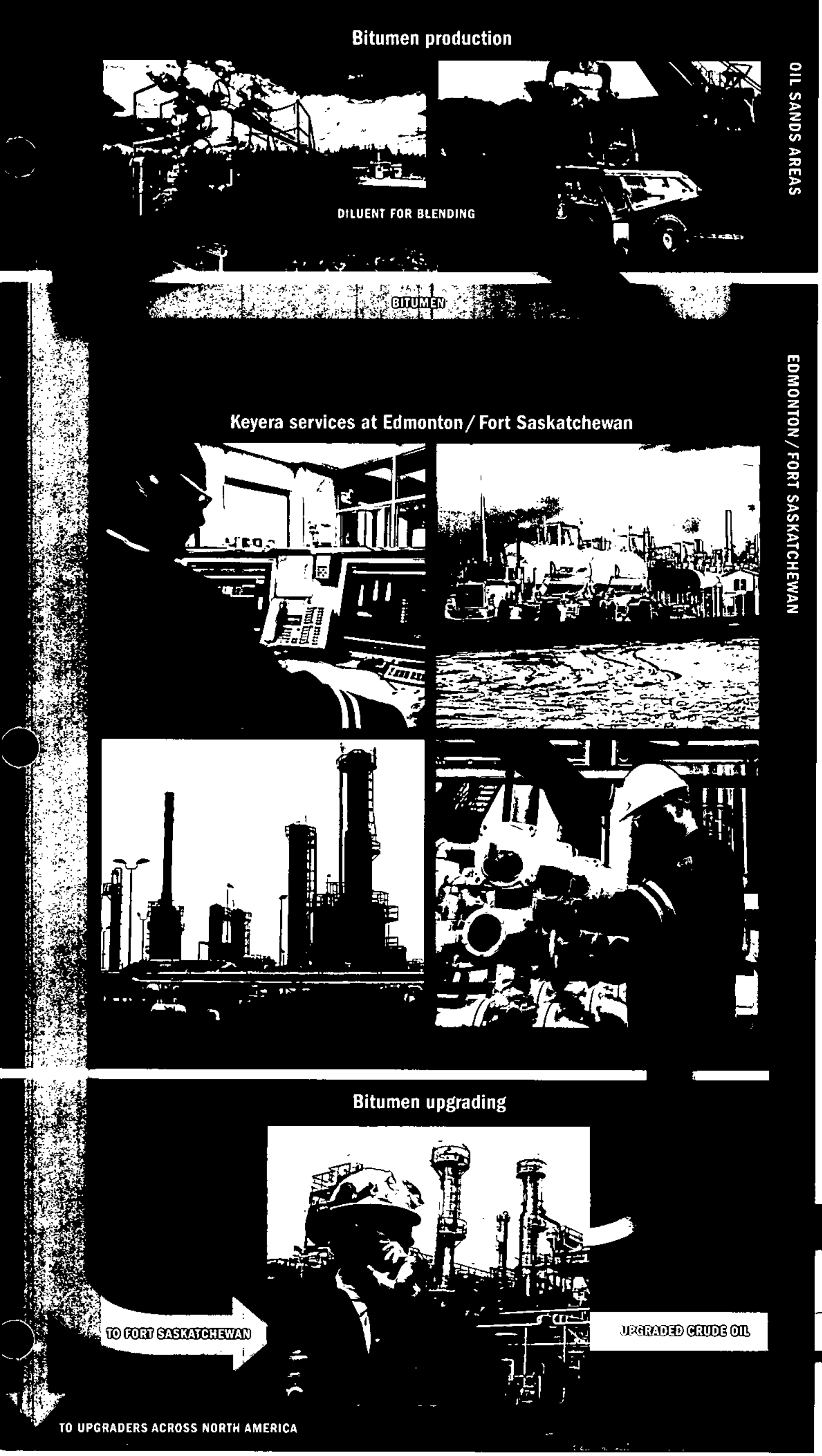
Keyera is ideally suited to provide products and services

Today, Keyera has the only underground condensate storage facilities in Fort Saskatchewan and is one of the largest suppliers of condensate to the oil sands sector. Our facilities in Edmonton and Fort Saskatchewan are connected to a number of pipeline systems and other facilities in the area.

Keyera has extensive, interconnected infrastructure

Keyera owns or controls about 65,000 barrels per day of NGL fractionation capacity, 8.9 million barrels of underground storage, five NGL pipelines, a pipeline logistics terminal, three truck terminals and two rail terminals. This infrastructure is interconnected with other Keyera facilities and to many of the major facilities and other pipelines in the area.





Bitumen is extracted using surface mining *when it is close to the surface or produced from well bores (referred to as in situ extraction) when the resource is too deep for surface mining. In situ recovery techniques include steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).*

Bitumen is highly viscous (like molasses) *and must be blended with a lighter product, referred to as diluent, in order for it to flow in pipelines.*

Numerous products and services will be required *to support the increasing amounts of bitumen production expected over the next two decades.*

Keyera is uniquely positioned to provide diluent products, *diluent storage and rail, truck and pipeline logistics services.*

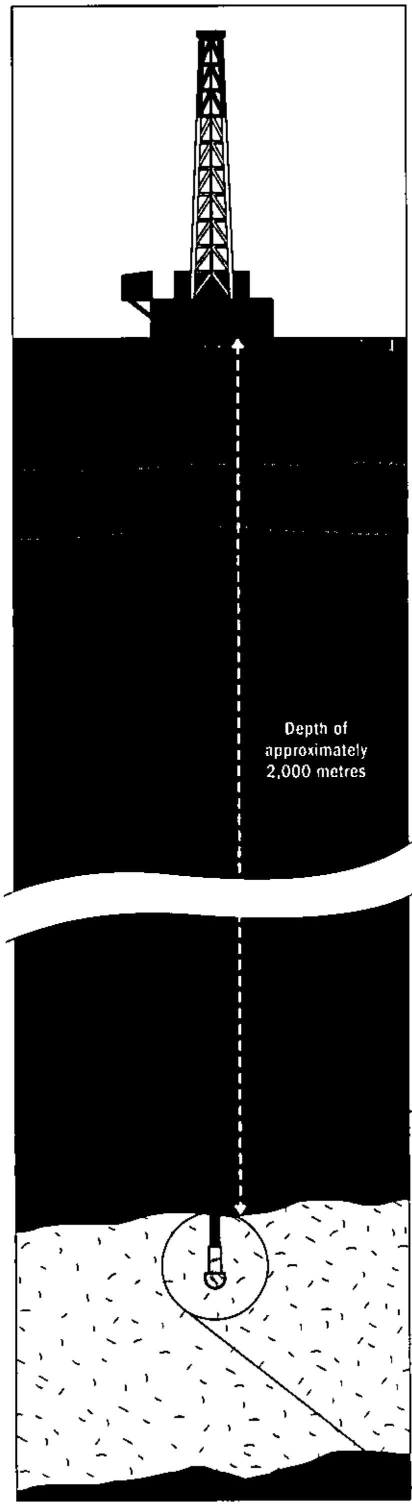
Upgrading is required to process the bitumen *into synthetic crude oil before delivery to refineries for processing into consumer products like gasoline, diesel and jet fuel.*

Much of the bitumen is expected to be upgraded *into crude oil in Alberta's Industrial Heartland, where Keyera's facilities are located.*

Meeting the growing demand for NGL storage

With existing undeveloped land atop the underground salt formation and operational expertise to perform the cavern washing function, Keyera is ideally positioned to create additional underground storage capacity.

How underground NGL storage caverns are created



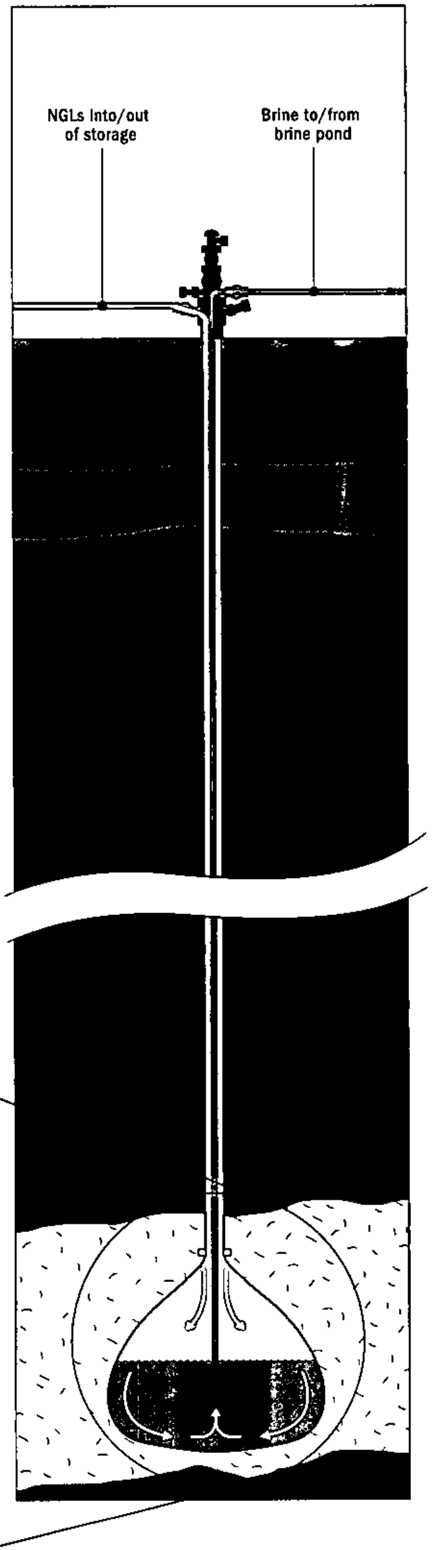
To create a new storage cavern, like the one currently underway at our Fort Saskatchewan facility, we bring a drilling rig on site to drill a hole to a depth of approximately two kilometres into the Lotsburg salt formation. This hole is lined with pipe, called casing.

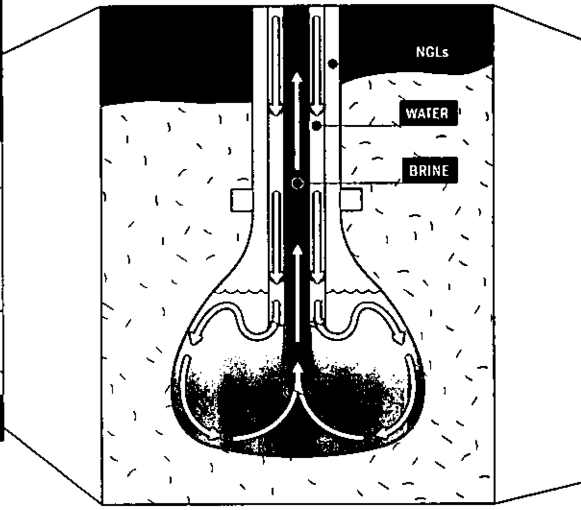
Two tubing strings are inserted into the casing (one inside the other) and a wellhead unit is attached to the casing at the surface. This creates three channels, allowing fluids to flow separately between the surface and the cavern.

With the tubing in place, water is pumped down the larger tubing string and into the salt formation. The water dissolves salt, becoming brine. The brine is returned to the surface through the inner tubing string. NGLs, often propane, are injected into the outer casing and pumped down to the top of the salt cavity to act as a buffer to protect the integrity of the cavern ceiling and the piping located there.

Over 18 to 24 months, water pumped into the formation gradually enlarges the cavern, creating a pear shaped profile. When the cavern has reached its optimal size, (usually between 750,000 and one million barrels of capacity), saturated brine is used instead of water to ensure the cavern doesn't grow any larger. Upon removal of the inner tubing string, the cavern is ready to be put into service.

Once operational, as NGLs are pumped into the cavern for storage, brine is displaced to the surface and deposited in large brine ponds. To remove NGLs from storage for delivery to customers, brine from the surface ponds is allowed back into the cavern, displacing NGLs to the surface.





Strategic rationale for adding storage

Our long term vision

A key goal in Keyera's long-term strategy is to become the premiere logistics, storage and NGL provider to the oil sands sector in the Edmonton/Fort Saskatchewan area. Keyera holds a sizeable land position and has significant energy infrastructure in this Industrial Heartland area, where much of the upgrading of bitumen from the oil sands is expected to occur. Our interconnected facilities allow us to fractionate, store, transport and deliver NGL products, such as propane, butane and condensate, into most of the pipelines, petrochemical plants and storage facilities in the area. As bitumen production increases, demand for additional condensate for use as diluent will increase, as will the need to store diluent products to manage the expected variability in diluent demand.

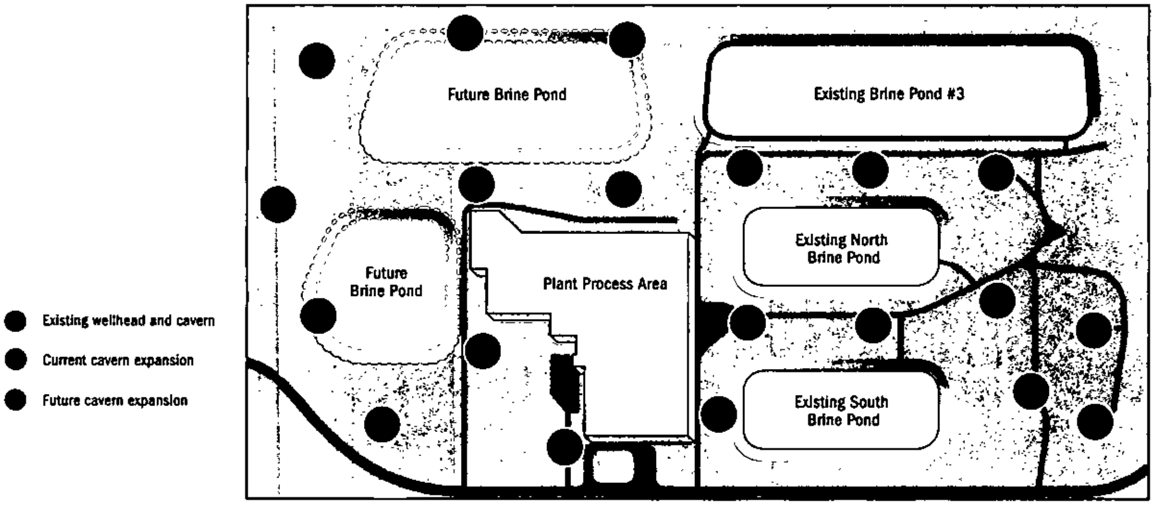
One of our key strategies is to position our assets in the Fort Saskatchewan area to meet the growing demand for oil sands related services.

Enhancing our competitive advantage

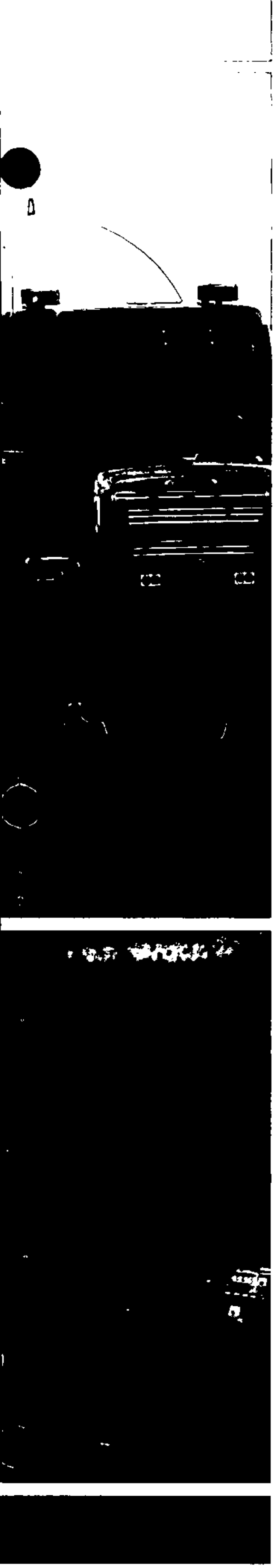
Keyera has a significant competitive advantage with respect to storage services in the Fort Saskatchewan area. We own or control about one third of all the existing underground storage in Fort Saskatchewan and currently we are the only provider of underground condensate storage in the region. To enhance this competitive advantage and to meet the growing need for storage, in late 2007 we initiated a multi-year project to use a portion of our undeveloped land to create four new underground storage caverns at an overall cost of $70 to $80 million.

When completed, the four caverns will increase our storage capacity of propane, butane, condensate and other hydrocarbons, such as off-gases (a byproduct of the upgrading process), by three million barrels to 11.9 million barrels. Work on the first cavern is underway and is expected to be operational in late 2009. After completing the four caverns, sufficient room will remain to add another six caverns, giving us the capability to double our current storage capacity to over 17 million barrels.

Keyera's Fort Saskatchewan NGL Fractionation and Storage Facility



Our goal is to become the premiere logistics, storage and NGL products provider in the Edmonton/Fort Saskatchewan area. Our interconnected facilities allow us to effectively source, fractionate, store and transport NGL products into key markets.



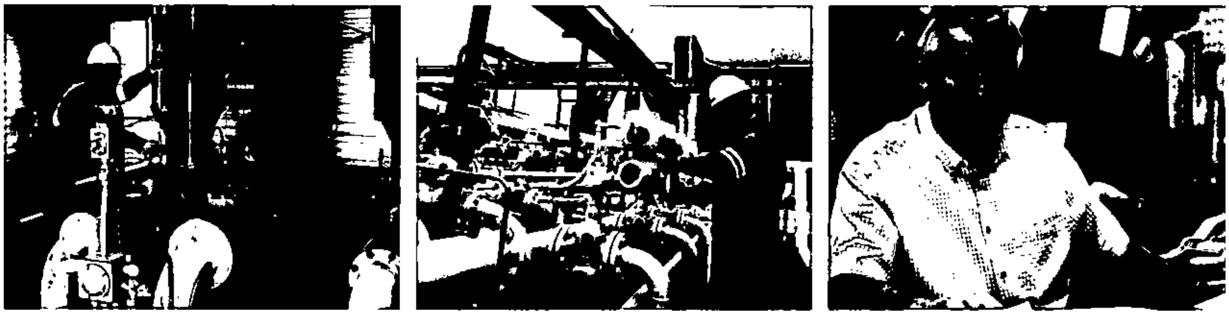
Other projects support oil sands strategy

Fourth pipeline increases operational capability

To support our storage expansion project and significantly enhance operational flexibility, we are adding a fourth pipeline connecting our Edmonton logistics and pipeline terminal with our NGL fractionation and storage facility in Fort Saskatchewan. This $8 million, 30-kilometre pipeline project is a key link in the development of our NGL strategy. When tie-ins are complete in 2008, we will be able to direct the flow of condensate, propane, butane and NGL mix in either direction between these two locations with greater flexibility and at increased volumes. This will make it easier to supply NGLs to our customers when they need it and allow us to increase the rates at which we can move products in and out of the 10 storage caverns at our Fort Saskatchewan facility.

Truck rack expansions enhance product handling services

In 2007, we completed construction of a condensate truck loading rack at our Rimbey gas plant, which has increased our capacity to deliver condensate directly to the regional market. We also initiated an expansion of the truck rack at our Fort Saskatchewan facility. This $5.5 million project is designed to enhance our product loading services and provide us with increased operational flexibility to load and unload specification products as well as NGL mix, condensate and crude oil. We expect the expansion to be operational in the second quarter of 2008.



Seizing growth opportunities

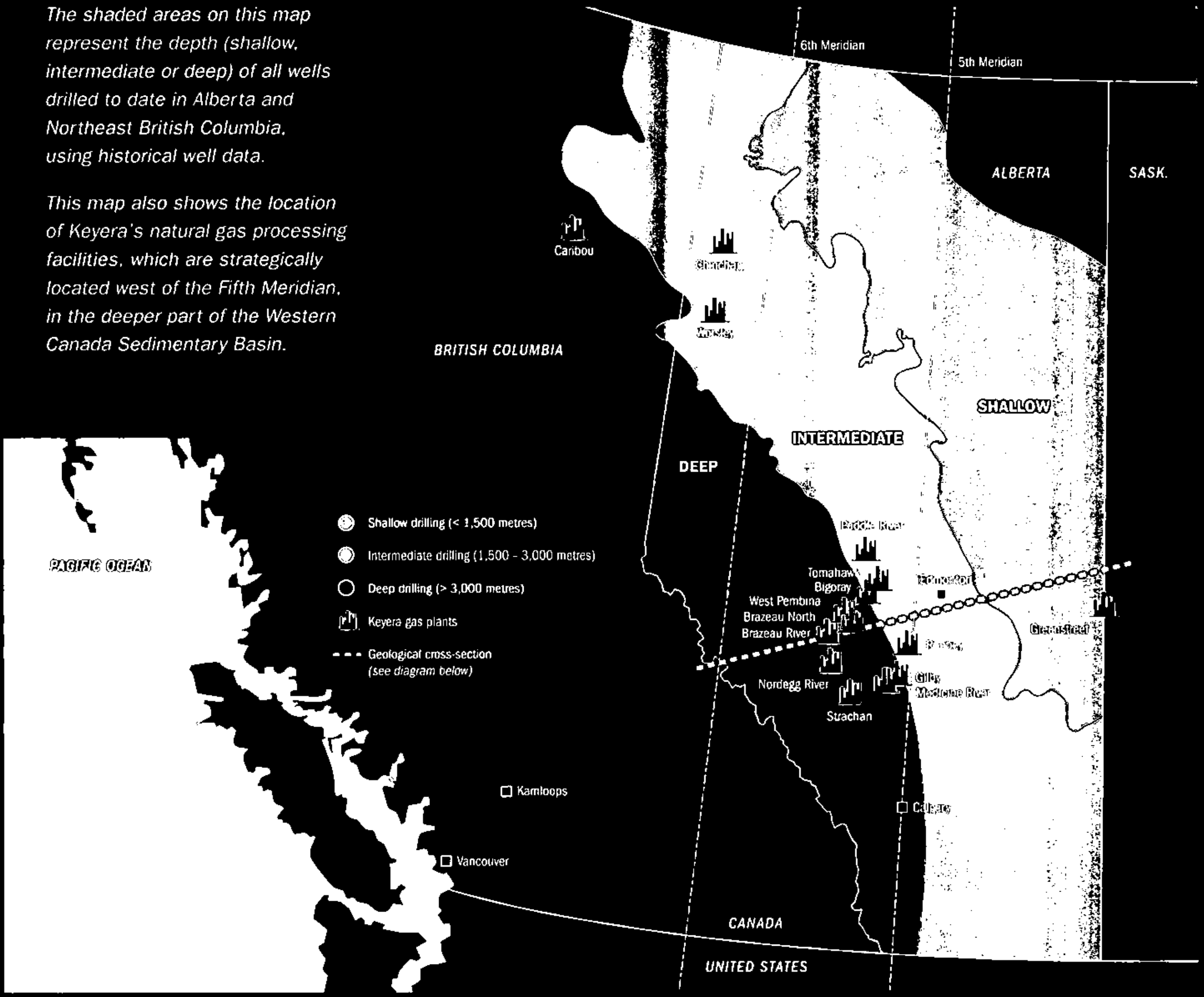
In 2007, we increased our ownership to 100% of Rimbey Pipeline Limited Partnership, which owns the Edmonton logistics and pipeline terminal and the NGL pipeline system connecting our Rimbey gas plant to Edmonton. With this acquisition, we now have full control over these strategic assets. We are also enhancing the connectivity of our assets by expanding our pipeline connections to other major pipelines and facilities, especially those that carry NGLs into the Fort Saskatchewan hub and diluent to Fort McMurray. As new oil sands pipelines are built and new upgrading facilities are constructed, we will continue to explore ways of enhancing our pipeline connections and services.

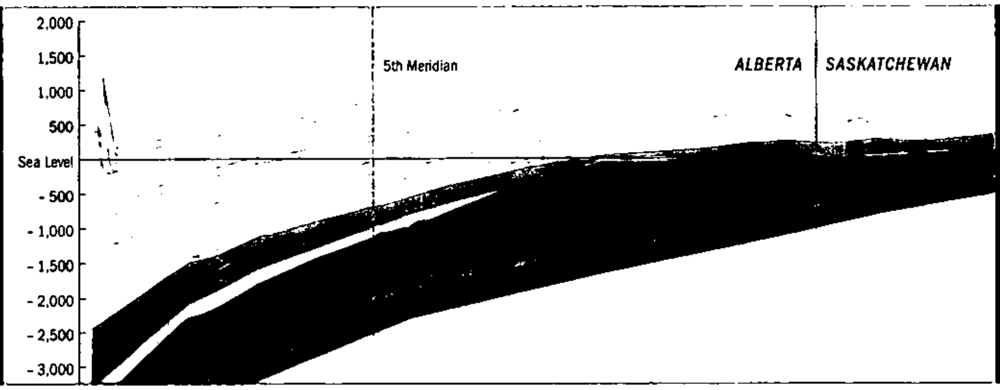
Assets that support natural gas producers

Our large facilities have unutilized capacity, flexible processing capabilities and extensive gathering systems – attributes that allow producers to connect their production quickly and maximize their netbacks.

The shaded areas on this map represent the depth (shallow, intermediate or deep) of all wells drilled to date in Alberta and Northeast British Columbia, using historical well data.

This map also shows the location of Keyera's natural gas processing facilities, which are strategically located west of the Fifth Meridian, in the deeper part of the Western Canada Sedimentary Basin.





This diagram is a geological cross-section of the area represented by the diagonal dotted line on the map above. It illustrates the increasing depth of the basin as one moves west, toward the Rocky Mountains.

West of the Fifth Meridian – the future of the basin

The area west of the Fifth Meridian is still largely undeveloped, with multiple gas prone zones that are typically larger and richer in NGLs. Clearly, this area represents the future of the Western Canada Sedimentary Basin.

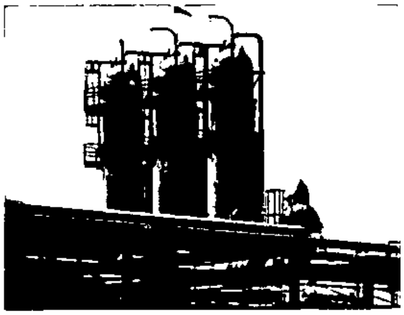
Versatile facilities in strategic locations

Keyera's gathering and processing facilities are strategically located on the western side of the Western Canada Sedimentary Basin, predominantly in areas west of the Fifth Meridian. The lands west of the Fifth Meridian are relatively less explored and have significant geological potential with multiple gas-prone zones. Deeper zones often contain larger reserves and may also contain high levels of hydrogen sulphide, carbon dioxide and NGLs. As a result, gas from these zones frequently requires specialized processing and attracts higher processing fees.

Keyera's facilities and the services we offer are well suited to handle this gas. Our large plants have versatile processing capabilities and broad capture areas, making it easier for producers to tie in their production. Our ability to process both sweet and sour gas, extract NGLs and offer a range of other complementary services that allow producers to maximize value from the raw gas they deliver to our facilities has contributed to the growth in our gathering and processing business.

Adapting to change

In October 2007, the Alberta Government announced significant changes to the Alberta royalty regime for 2009. Although we expect to see reduced activity in the short term as producers adapt to the new royalty structure, we believe the prospects for the longer term development of the basin are positive. We view the government's commitment to maintain incentives for deep-gas drilling as a positive sign for drilling west of the Fifth Meridian and believe that the proposed shallow rights reversion may help to stimulate more shallow completions.



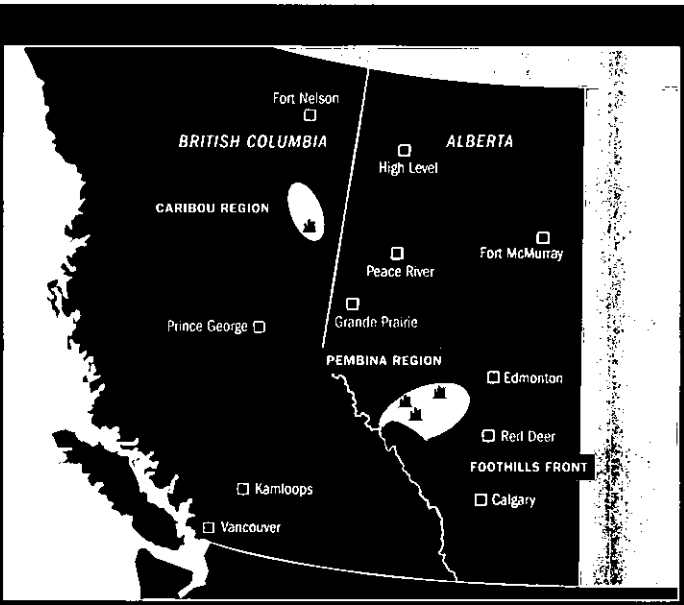
Looking ahead

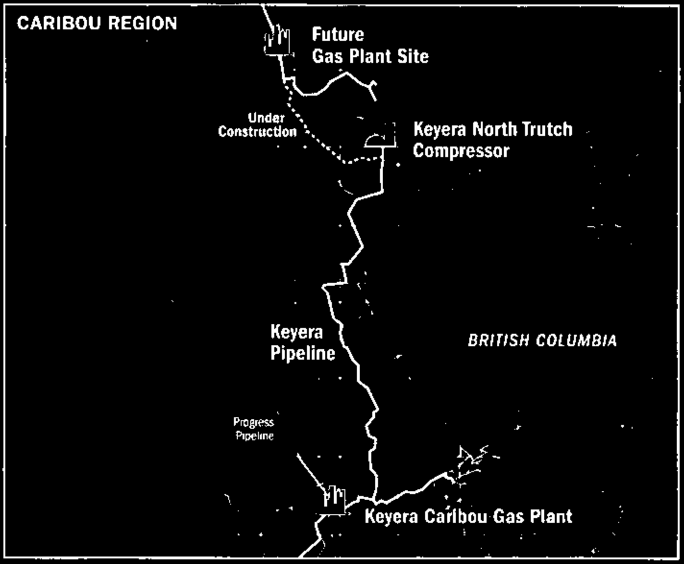
Today, we continue to see producer activity in areas surrounding many of our plants. In these challenging times, producers are becoming more selective with their drilling targets. As they look for more attractive economics, we anticipate that they will pursue opportunities close to existing infrastructure that can offer them higher netbacks, factors that favour Keyera's facilities.

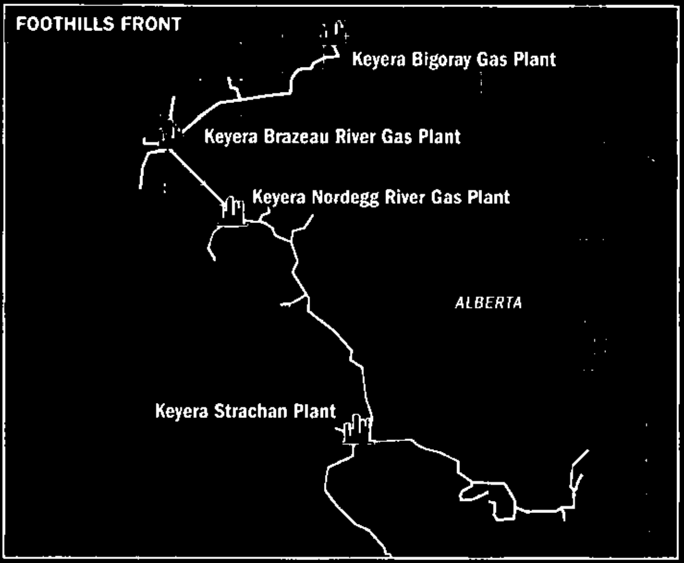
We expect the Western Canada Sedimentary Basin will continue to be a key source of natural gas supply for many years. Given the barriers to entry and the competitive location of our facilities in the basin, we are well placed to maximize the strengths of our gathering and processing business strategy.

Great geology and pipeline infrastructure keys to success

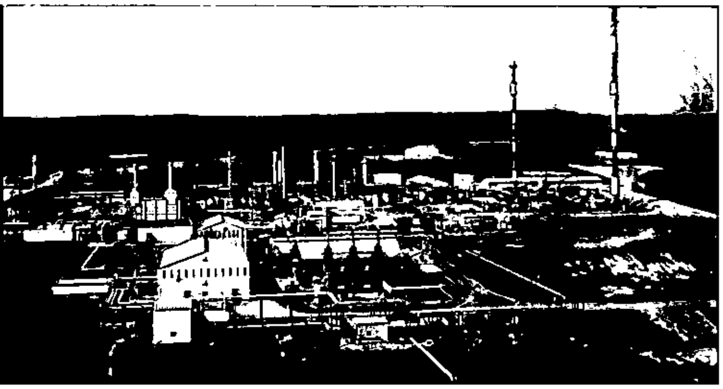
Recent trends are seeing natural gas producers targeting reservoirs with gas compositions that provide higher netbacks and are close to existing plant and pipeline infrastructure. Because of the strategic location of Keyera's facilities, most of which are located on the western side of the Western Canada Sedimentary Basin, we are well situated to serve these producers.







Three areas that experienced significant producer activity in 2007 were the Caribou, Pembina and Foothills front regions. In each of these areas, we partnered with the producers in various ways to connect their production quickly to Keyera infrastructure.



Record throughput driven by producer activity around our plants

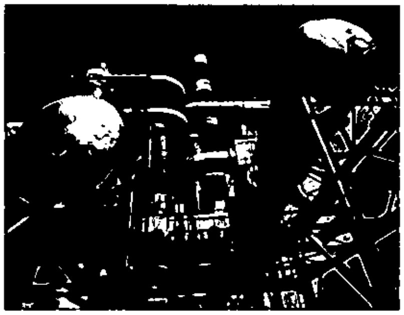
During 2007, producers delivered record throughput volumes to Keyera gas processing plants, as producers targeted liquids-rich natural gas prospects on lands adjacent to existing infrastructure to maximize their netbacks.

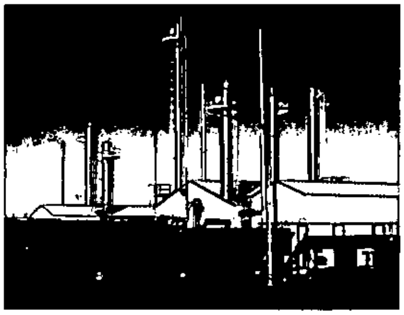
Caribou – pipeline construction stimulates activity

In early 2006, we constructed a 48-kilometre pipeline to the north of the Caribou gas plant in northeast British Columbia, opening up approximately 1,000 square kilometres of undeveloped lands. In conjunction with the pipeline expansion, we increased the processing capacity of the plant by 25 million cubic feet per day to 65 million cubic feet per day. With producer activity continuing to increase, we extended the pipeline to capture new gas development in 2007, and in December we announced a second, 24-kilometre extension to connect with a pipeline system acquired earlier in the year. With the plant utilization exceeding 75% at year end, we have initiated detailed engineering for a possible second expansion of the plant.

Pembina region – sour gas processing at a premium

The Pembina region may be the most exciting light oil development underway in Alberta. Oil from the Nisku formation contains natural gas in solution with the oil. The gas, which contains high levels of hydrogen sulphide, is separated from the oil and delivered to sour gas processing plants in the area. In 2007, production increased to a point where Keyera's three plants in the region reached their sour gas capacity. To meet the processing demands, we constructed infrastructure to divert sour gas to other Keyera facilities in the Foothills region, added a new acid gas injection reservoir and are exploring options for expanding the sour gas capacity at our Bigoray gas plant.

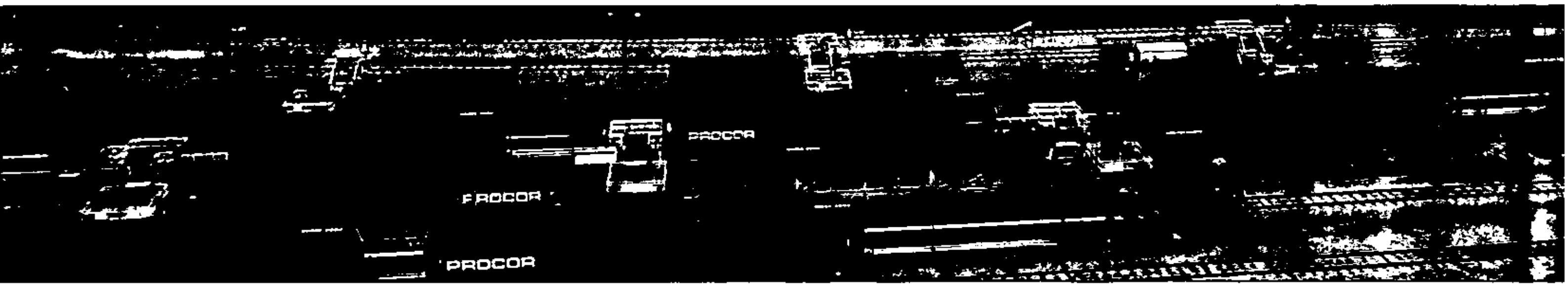




Foothills front – new pipelines attract new processing volumes

In 2007, a number of new natural gas production areas were developed to the west of Keyera's gathering systems in the Foothills front region of west-central Alberta. Keyera worked with producers in the area to build the necessary pipeline infrastructure to connect these new areas to Keyera facilities for processing, partnering with the producers on two of the pipeline projects.

The proposed ethane extraction project at Rimbey is another example of our expertise in identifying and capturing opportunities at our existing facilities. This project will benefit Keyera and the natural gas producers, as well as support the long-term ethane supply requirements of Alberta's petrochemical industry.



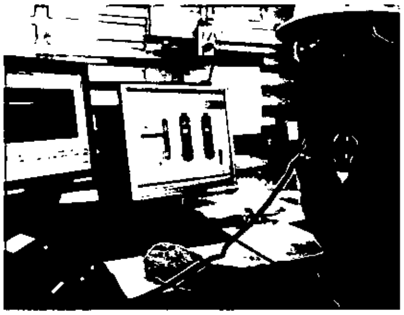
The Rimbey gas plant – a modern energy complex

Strategically located in west-central Alberta, approximately 100 kilometres southwest of Edmonton, Keyera's Rimbey gas plant is a state-of-the-art energy complex, offering a comprehensive suite of natural gas processing services.

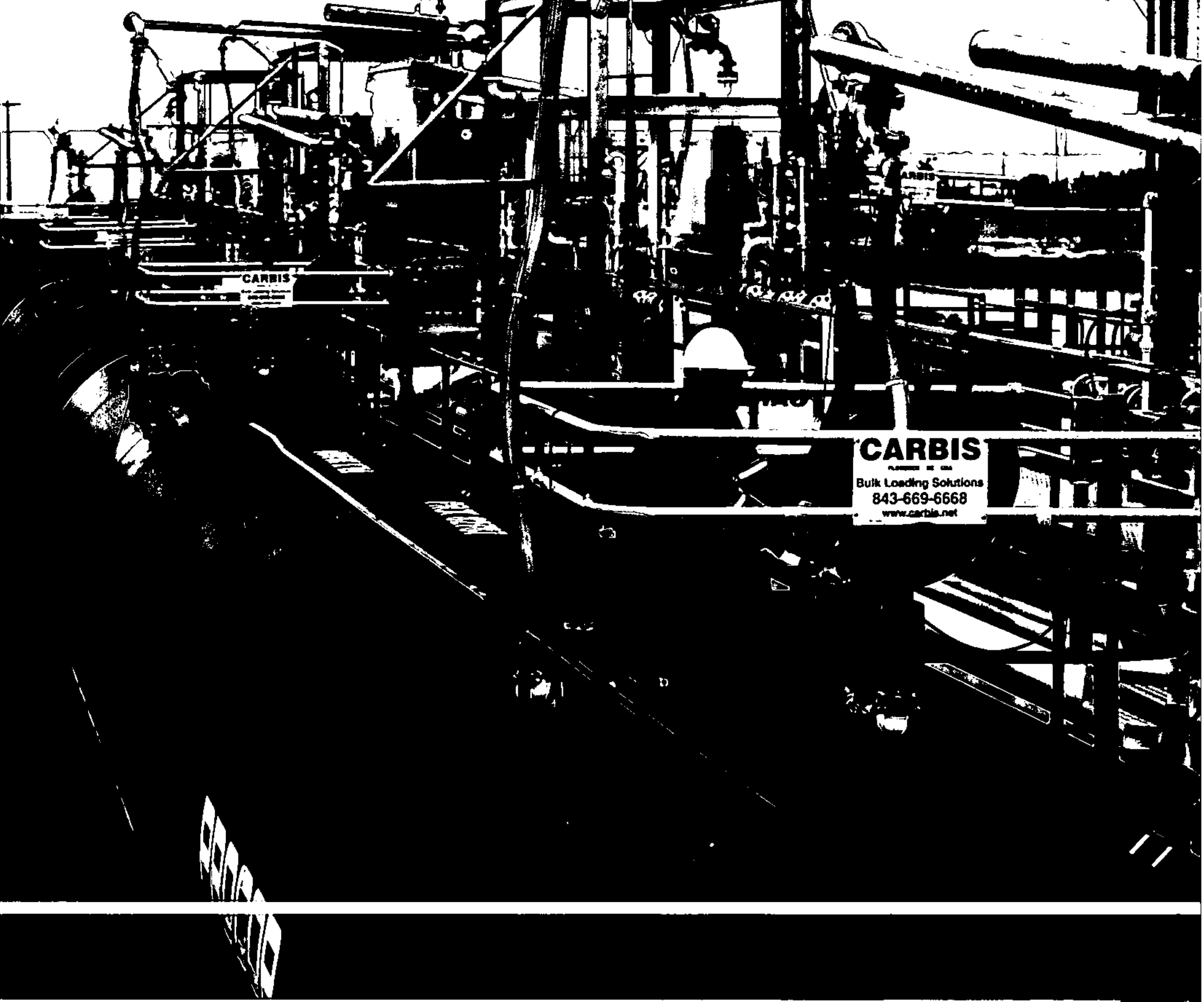
Over the years, the Rimbey complex has benefited from significant capital investment to increase processing capacity, enhance services, maintain reliability and meet current environmental standards. The size of the facility and the scope of its processing options have allowed Keyera to initiate a number of innovative projects to create incremental value. They include the liquefaction and sale of CO_2 captured from the raw gas stream and the production of "frac" oil, both of which have enhanced profitability and resulted in new business opportunities. The plant's "deep cut" liquids recovery system extracts more than 90% of the NGLs from the raw gas processed and the Rimbey pipeline provides direct access to the Fort Saskatchewan energy hub for these products. Today, the complex offers producers a low cost, high netback solution. Keyera is clearly the preferred processing alternative in the region.

Ethane extraction project creates incremental value

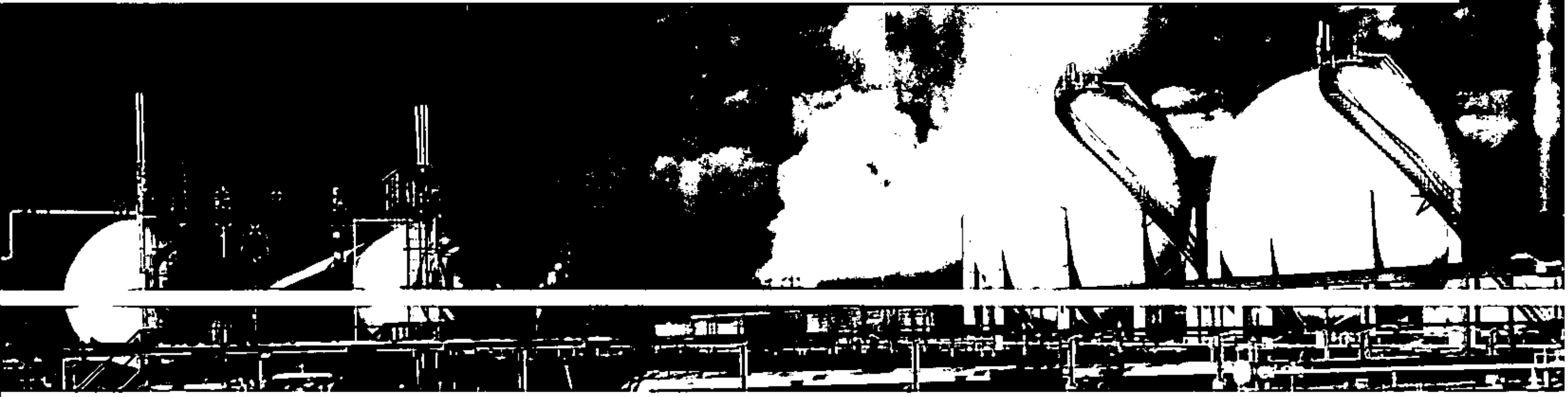
In 2007, Keyera announced plans to add ethane extraction capability at the plant. If approved by the Energy Resources Conservation Board, Keyera expects to spend $26 million to modify the existing NGL extraction process, install new compression equipment and construct a 32-kilometre ethane delivery pipeline. The project is designed to allow the Rimbey plant to extract up to 5,000 barrels per day of saleable ethane from raw gas processed at the plant. A significant portion of this ethane is currently consumed as fuel gas within the plant and would therefore be incremental to the supply of ethane in Alberta. Keyera believes the project also has the potential to extend the plant's economic life and further enhance our competitive advantage in sour gas processing in the region.



The proposed project is in keeping with the Government of Alberta's Incremental Ethane Extraction Policy to increase the supply of ethane available in Alberta for value-added upgrading. We anticipate that this project will also improve resource recovery and generate positive economic spin offs, contributing to the economic, orderly and efficient development of Alberta's resources.



Our strategic NGL storage assets and our pipeline connections at Edmonton and Fort Saskatchewan, combined with the flexibility gained by having terminals and rail cars, clearly create a competitive advantage for our marketing group that we plan to strengthen as we go forward.



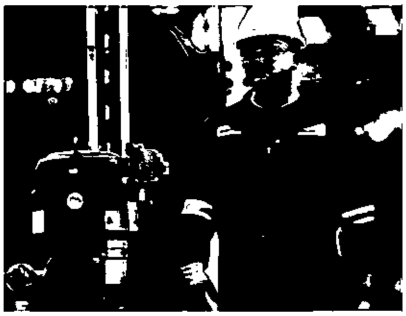
NGL marketing and crude oil midstream – integration creates competitive advantage

Keyera's marketing and crude oil midstream activities are a natural extension of our other two business lines. Our marketing group utilizes Keyera's NGL processing, storage and transportation infrastructure to source NGLs and deliver specification products to customers throughout North America. This integration is becoming increasingly advantageous as condensate is sourced to meet the growing demand for diluent in the oil sands sector.

Infrastructure expansion benefits marketing business

Construction of an offload facility at our rail terminal in Edmonton in 2006 has allowed us to import up to 11,000 barrels per day of condensate into the Alberta market. Throughout 2007, we have used this facility to augment our western Canadian condensate supply and capture pricing premiums. We use our storage capacity in Fort Saskatchewan to manage fluctuations between product supply and demand, particularly for propane, and to capture buying opportunities in the market. Additional storage capacity, as well as the truck rack expansion and the fourth NGL pipeline, will further strengthen Keyera's marketing advantage while generating fee-for-service revenues.

Propane marketing is a growing part of our marketing business. From our Houston office, we support a customer base that extends throughout the western part of the continental United States. In 2007, we acquired a propane terminal in Superior, Montana, complementing the three propane terminals in the U.S. that we acquired in 2006.



Recently, we have utilized our gathering and processing and pipeline facilities to provide crude oil midstream services. This business shares the same characteristics as the other parts of our marketing business: namely specialized market expertise, access to unique infrastructure, and skilled operational resources. As we expand and acquire additional plants and pipelines, we are constantly looking for new NGL marketing and crude oil midstream opportunities.

Keyera is committed to conducting its business in a way that balances diverse stakeholder expectations, respects the environment and emphasizes the health and safety of our employees and communities.

An Engaged and Responsible Corporate Citizen

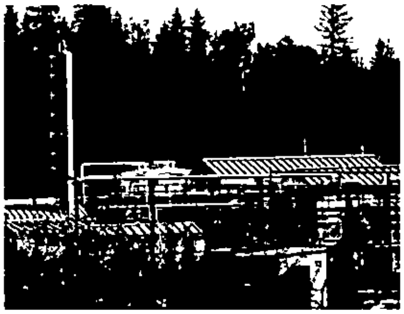
Demonstrating environmental leadership

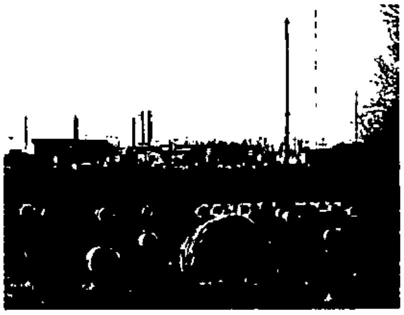
Keyera recognizes and values the importance of responsible environmental stewardship and has made significant investments in infrastructure to improve efficiencies and enhance environmental performance.

Combining environmental responsibility with sound business strategy

Keyera has a strong track record of identifying and pursuing win-win opportunities that benefit the environment and are good business decisions. We have been ahead of the curve in addressing greenhouse gas emissions by implementing acid gas injection, carbon dioxide liquefaction and waste heat recovery initiatives. Since 2004, we have been removing and liquefying CO_2 from the raw gas stream at our Rimbey gas plant, taking what would otherwise be part of a waste stream and turning it into a saleable product. In doing so, we created a new revenue stream at the plant, enhanced our sulphur recovery process and reduced plant emissions. As well, since 2005 we have been using heat contained in exhaust from a large turbine at our Strachan gas plant to generate steam at the plant, resulting in the combined benefit of reducing both emissions and fuel gas consumption. Keyera is also a leader in acid gas injection, a process widely recognized as one of the most environmentally sound ways of handling the waste products associated with sour gas processing, including CO_2. Five of our facilities use acid gas injection to dispose of H_2S, CO_2 and other waste gases.

Building on this track record of successful projects, we are pursuing other opportunities to optimize our environmental performance. In 2008, we will be installing a flare gas recovery system at our Rimbey plant, one of only a few in Alberta.





Building on our long term environmental strategy

Keyera recognizes that addressing environmental issues is a shared responsibility and we are committed to working with government, industry and public interest stakeholders to address the challenges. Beyond the steps we have taken to comply with Alberta's new greenhouse gas legislation in 2007, we are also actively preparing for new regulatory requirements on the horizon. We believe that we can generate many opportunities within our facilities to reduce environmental impacts and are open to exploring projects with our business partners, customers and others.

Investing in communities and creating safe working environments

A leader in health and safety

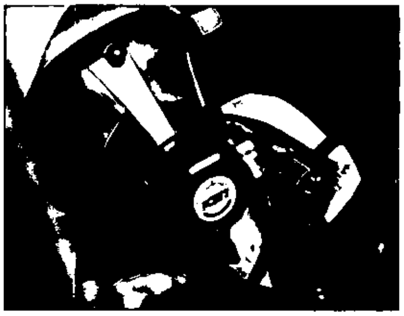
Keyera strives to be a leader in health and safety and is dedicated to fostering safe and healthy environments at our facilities and in the surrounding communities. Our goal is to be proactive in our approach, emphasizing safety as an integral part of every task not only in the work place, but also in daily living.

Through a partnership with Lakeland College, our Competency Management and Development System has been developed into a post secondary certification program available province wide. We are extremely pleased that the system is now being used by over 3,000 employees in more than 40 major energy companies.

Involving stakeholders in emergency response planning

We also understand the importance of being prepared to respond to emergencies and unexpected events and regularly hold exercises at all of our facilities to test our effectiveness. In 2007, we teamed up with other emergency response and health care providers in the area, as well as two levels of government, to hold an emergency response exercise at our Strachan gas plant. Our goal was to enhance communication effectiveness and improve response times by sharing information and building on the spirit of cooperation.

> "Keyera's willingness to engage other partners, including municipal and provincial departments, is an example to other industries."
>
> – *Alberta Emergency Management Agency*



Investing in young people in local communities

Keyera has been a leader in developing the Career Pathways and Junior Achievement programs in Rocky Mountain House and Drayton Valley. Through these programs, we work in partnership with community leaders and educators to provide education, training, mentorship, scholarships and employment opportunities for young people in their local communities.

We are proud of our track record of being an engaged and responsible corporate citizen and remain committed to supporting our communities.

Part of achieving a healthy and safe environment lies in the proper training, education and mentoring of employees and contractors. We work hard to make sure our employees have opportunities to continually improve their skills and knowledge base.

Management's Report

The condensed consolidated financial statements in this Summary Annual Report provide an overview of Keyera's performance and should be read in conjunction with the audited consolidated financial statements, notes, and management's discussion and analysis for the years ended December 31, 2007 and 2006.

Keyera management is responsible for the preparation of the accompanying condensed consolidated financial statements, which have been prepared by management in accordance with Canadian generally accepted accounting principles and include amounts based on estimates and informed judgements. Financial information contained elsewhere in this Summary Annual 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 report operating and financial results realistically and that Keyera's assets are safeguarded.

Deloitte & Touche LLP, our independent auditors, appointed by the Board of Directors, have completed their audit and submitted their report. The Audit Committee, consisting of independent directors, has reviewed the consolidated financial statements with management and the independent auditors and has reported to the Board of Directors. The Board has approved the consolidated financial statements.

David G. Smith

Jim V. Bertram
President and Chief Executive Officer

David G. Smith
Executive Vice President and Chief Financial Officer

February 22, 2008

Auditors' Report

To the Unitholders of Keyera Facilities Income Fund

We have audited the consolidated statements of financial position of Keyera Facilities Income Fund (the "Fund") as of December 31, 2007 and 2006 and the related consolidated statements of net earnings, comprehensive income and deficit and cash flows for each of the years then ended. Such consolidated financial statements and our report thereon dated February 22, 2008, expressing an unqualified opinion (which is not included herein), appears in the Fund's 2007 Financial Report. The accompanying condensed consolidated financial statements are the responsibility of the management of Keyera Energy Management Ltd. Our responsibility, in accordance with the applicable Assurance Guideline of The Canadian Institute of Chartered Accountants, is to express an opinion on such condensed consolidated financial statements in relation to the complete consolidated financial statements.

In our opinion, the accompanying condensed consolidated statements of financial position as of December 31, 2007 and 2006 and the related condensed consolidated statements of net earnings, comprehensive income and deficit and cash flows for each of the years then ended fairly summarize, in all material respects, the related complete consolidated financial statements in accordance with the criteria described in the Guideline referred to above.

These summarized financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles. Readers are cautioned that these statements may not be appropriate for their purposes. For more information on the Fund's financial position, results of operations and cash flows, reference should be made to the related complete consolidated financial statements.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Canada

February 22, 2008

Condensed Consolidated Statements of Financial Position

As at December 31 *(Thousands of Canadian dollars)*	**2007** **$**	2006 $
Assets		
Current assets		
Cash	15,657	-
Accounts receivable	243,889	160,112
Inventory	76,594	53,939
Asset held for sale	-	4,200
Other current assets	2,299	4,327
	338,439	222,578
Property, plant and equipment	914,087	924,947
Intangible assets	6,394	10,553
Goodwill	71,234	64,934
Future income tax assets	845	-
	1,330,999	1,223,012
Liabilities and Shareholder' Equity		
Current liabilities		
Bank indebtedness	-	96
Accounts payable and accrued liabilities	235,124	148,318
Distributions payable	7,658	7,251
Credit facilities	-	107,984
Current portion of long-term debt	20,000	-
	262,782	263,649
Long-term debt	313,243	215,000
Convertible debentures	21,476	23,542
Asset retirement obligation	37,807	34,533
Future income tax liabilities	145,214	65,424
	780,522	602,148
Non-controlling interest	-	2,744
Unitholders' equity		
Unitholders' capital	681,925	677,025
Deficit	(131,448)	(58,905)
	550,477	618,120
	1,330,999	1,223,012

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

Wesley R. Twiss
Director

James V. Bertram
Director

Condensed Consolidated Statements of Net Earnings, Comprehensive Income and Deficit

For the Years Ended December 31 *(Thousands of Canadian dollars, except unit information)*	**2007** **$**	2006 $
Operating revenues		
Marketing	**1,250,541**	1,161,899
Gathering and Processing	**187,490**	166,736
NGL Infrastructure	**41,110**	39,888
	1,479,141	1,368,523
Operating expenses		
Marketing	**1,172,010**	1,102,045
Gathering and Processing	**103,792**	96,558
NGL Infrastructure	**24,253**	23,956
	1,300,055	1,222,559
	179,086	145,964
General and administrative	**21,882**	18,892
Interest expense on long-term indebtedness	**16,077**	13,838
Other interest expense	**4,099**	4,318
Depreciation and amortization	**42,040**	39,843
Accretion expense	**2,482**	2,257
Impairment expense	**728**	373
	87,308	79,521
Earnings before income tax and non-controlling interest	**91,778**	66,443
Income tax expense (recovery)	**76,993**	(2,660)
Earnings before non-controlling interest	**14,785**	69,103
Non-controlling interest	**306**	1,025
Net earnings	**14,479**	68,078
Other comprehensive income	**-**	-
Comprehensive income	**14,479**	68,078
Deficit, beginning of year	**(58,905)**	(40,378)
Change in accounting policies	**3,184**	
Distributions to unitholders	**(90,206)**	(86,605)
Deficit, end of year	**(131,448)**	(58,905)
Weighted average number of units *(thousands)*		
– basic	**61,098**	60,604
– diluted	**61,098**	62,794
Net earnings per unit		
– basic	**0.24**	1.12
– diluted	**0.24**	1.10

Condensed Consolidated Statements of Cash Flows

For the Years Ended December 31 *(Thousands of Canadian dollars)*	**2007** **$**	2006 $
Net inflow (outflow) of cash:		
Operating activities		
Net earnings	14,479	68,078
Items not affecting cash:		
Depreciation and amortization	42,040	39,843
Accretion expense	2,482	2,257
Impairment expense	728	373
Unrealized loss (gain) on financial instruments	12,563	(263)
Loss on sale of assets	245	-
Future income tax expense (recovery)	72,645	(7,042)
Non-controlling interest	306	1,025
Asset retirement obligation expenditures	(213)	(160)
Changes in non-cash operating working capital	(25,450)	6,545
	119,825	110,656
Investing activities		
Capital expenditures	(25,313)	(73,868)
Acquisition of non-controlling interest	(6,716)	-
Proceeds on sale of assets	4,704	-
Additions to intangibles	-	(1,115)
Changes in non-cash working capital	(1,114)	(651)
	(28,439)	(75,634)
Financing activities		
(Repayment) issuance of debt under credit facilities	(107,984)	41,984
Issuance of long-term debt, net of financing costs	118,895	-
Issuance of trust units	3,255	4,252
Distributions paid to unitholders	(89,799)	(86,509)
Distributions or dividends paid to others	-	(479)
	(75,633)	(40,752)
Net cash inflow (outflow)	15,753	(5,730)
(Bank indebtedness) cash, beginning of year	(96)	5,634
Cash (bank indebtedness), end of year	15,657	(96)

Keyera Facility Capacities and Utilization Rates

Natural Gas Processing Facilities

Facility	*Ownership Interest (%)*	*License Gross Capacity (MMcf/d)*	*Average Daily Throughput (MMcf/d)*	*Utilization Rate (%)*
Rimbey	86	422	265	63
Strachan	86	275	178	65
Brazeau River	52	218	90	41
Chinchaga	100	148	36	24
Bigoray	90	85	35	41
Paddle River	87	81	21	26
Nordegg River	78	75	54	73
Gilby	78	71	39	55
Caribou	100	65	47	73
Medicine River	24	64	33	51
Brazeau North	68	49	14	29
West Pembina	74	43	18	42
Greenstreet	100	25	5	22
Worsley	100	20	7	33
Tomahawk	68	16	1	6
North Star[1]	87	6	0	2
Total		1,663	843	51

[1] *Keyera sold its interest in North Star effective January 1, 2008.*

NGL Processing and Transportation

Facility	*Ownership Interest (%)*	*License Gross Capacity (bbls/d)*	*Average Daily Throughput (bbls/d)*	*Utilization Rate (%)*
NGL Processing				
Rimbey Gas Plant	86	31,500	14,701	47
Fort Saskatchewan *(Keyera)*	77	30,200	28,409	94
Gilby Gas Plant	78	3,200	1,719	54
Fort Saskatchewan				
(Dow NGL processing)	18	30,000	22,401	75
(Dow De-ethanizer)	10	69,200	45,514	66
NGL Pipelines				
Fort Saskatchewan *(Keyera)*	77	210,000	141,246	67
Rimbey Pipe Line	100	45,000	36,869	82

NGL Storage Facilities

	Ownership Interest (%)	*Gross Capacity (bbls)*	*Net Capacity (bbls)*
Fort Saskatchewan *(Keyera)*	77	8,900,000	6,827,000
Fort Saskatchewan *(Dow)*	18	2,000,000	360,000

Advisories

Note Regarding Non-GAAP Financial Measures

This Summary Annual Report 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 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 cash flow 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. Distributable cash flow is used to assess the level of cash flow generated from ongoing operations and to evaluate the adequacy of internally generated cash flow to fund distributions. 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 Summary Annual Report are 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; and expectations regarding Keyera's ability to raise capital and to add to its assets through acquisitions or internal growth opportunities.

Glossary

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.
Alberta's Industrial Heartland	A 470-square kilometre area northeast of Edmonton designated for heavy industrial development by the four municipal partners (Lamont, Strathcona, and Sturgeon counties and the City of Fort Saskatchewan) under a cooperative regime of municipal plans and policies that encourages, facilitates and plans industrial development while mitigating the impact of heavy industry.
API gravity	A scale developed by the American Petroleum Institute for measuring the density or gravity of oil; the higher the number, the lighter the oil.
bbls and bbls/d	Barrels and barrels per day.
bitumen	A naturally occurring, viscous (like molasses) mixture of hydrocarbons, with a gravity of less than 10° API. Bitumen cannot be refined into common petroleum products like gasoline, diesel or jet fuel without first being upgraded to synthetic crude oil.
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 petroleum product used to dilute bitumen so it can flow through pipelines. Condensate is the most commonly used diluent in the oil sands industry.
ethane	A natural gas liquid (NGL) with the molecular formula C_2H_6.
greenhouse gases	Gases that trap heat near the Earth's surface. These include carbon dioxide, methane, nitrous oxide and water vapour. These gases occur through natural processes (such as ocean currents, cloud cover, volcanoes) and human activities (such as the burning of fossil fuels).
in situ	"In place". If an oil sands deposit is too deep to mine from the surface, in situ recovery methods are required, such as steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).
midstream	The processing, storage and transportation sectors within the oil and gas industry that occur between the upstream (exploration, development and production) and downstream (refining, distribution and marketing) sectors.
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.
off-gases	Hydrocarbons derived from the distillation and upgrading of bitumen.
oil sands	A composition of sand, bitumen, mineral-rich clays and water.
propane	A natural gas liquid (NGL) with the molecular formula C_3H_8.
raw gas	A mixture containing methane plus all or some of the following: ethane, propane, butane, pentanes, condensates, nitrogen, carbon dioxide, hydrogen sulphide, helium, hydrogen, water vapour and minor impurities. Raw gas is the gas found naturally in the ground prior to processing.
sales gas	Natural gas that has been treated in a natural gas processing facility and is suitable for sale.
salt cavern	An underground NGL storage cavern that has been developed in a salt dome by the solution mining process.
sedimentary basin	A geographical area, such as the Western Canada Sedimentary Basin, in which much of the rock is sedimentary (as opposed to igneous or metamorphic) and is therefore likely to contain hydrocarbons.
sour gas	Raw gas with a relatively high concentration of sulphur compounds, such as hydrogen sulphide. All natural gas containing more than 1% hydrogen sulphide is considered sour. About 30% of Canada's natural gas production is sour, most of it found in Alberta and northeast British Columbia.
sulphur	A yellow mineral extracted from sour gas.
sweet gas	Natural gas that contains less than 1% hydrogen sulphide when produced.
synthetic crude oil	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.
upgrading	The process of converting bitumen into synthetic crude oil by increasing the ratio of hydrogen to carbon, either by removing carbon (coking) or by adding hydrogen (hydroprocessing).
viscosity	The resistance to flow or "stickiness" of a fluid. In general, a fluid with high viscosity resists motion because its molecular makeup gives it a lot of internal friction. A fluid with low viscosity flows easily because its molecular makeup results in very little friction when it is in motion.

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
Executive Director
and Deputy Chairman
National Grid plc
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
Smiths Cove, Nova Scotia

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,
Foothills Region

Steven B. Kroeker
Vice President,
Corporate Development

Bradley W. Lock
Vice President,
North Central Region

David A. Sentes
Vice President,
Comptroller

Head Office

Suite 600,
Sun Life Plaza West Tower
144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4

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

Stikeman Elliott LLP
Calgary, Alberta

Annual Meeting of Unitholders

May 13, 2008, 2:00 p.m.
Sun Life Plaza Conference Centre
144 – 4th Avenue S.W.
Calgary, Alberta

Investor Relations

John Cobb
Director, Investor Relations

Bradley White
Investor Relations Advisor

Toll Free: 1-888-699-4853
Direct: 403-205-7670
Email: ir@keyera.com

Website

www.keyera.com

Stability Rating

Standard & Poor's SR-3

2007 Trading Summary

Units Outstanding:
61.6 million (December 31)

Average Daily Trading Volume:
127,071 units

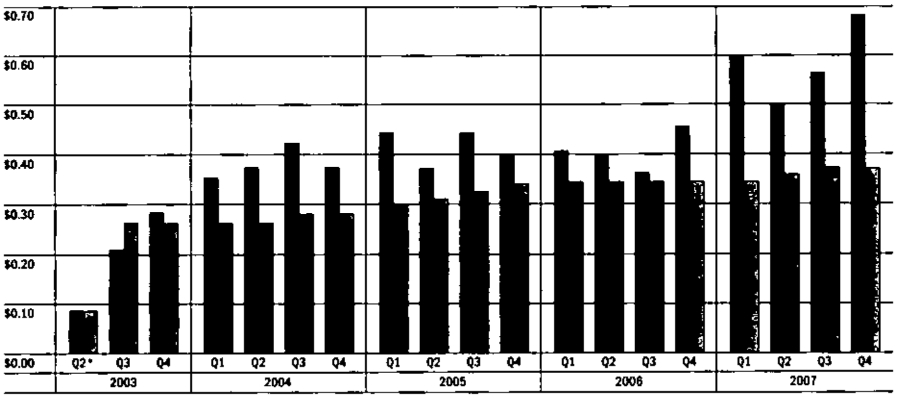
Trading Prices:
High: $20.11
Low: $15.51
Close: $19.90 (December 31)

(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*



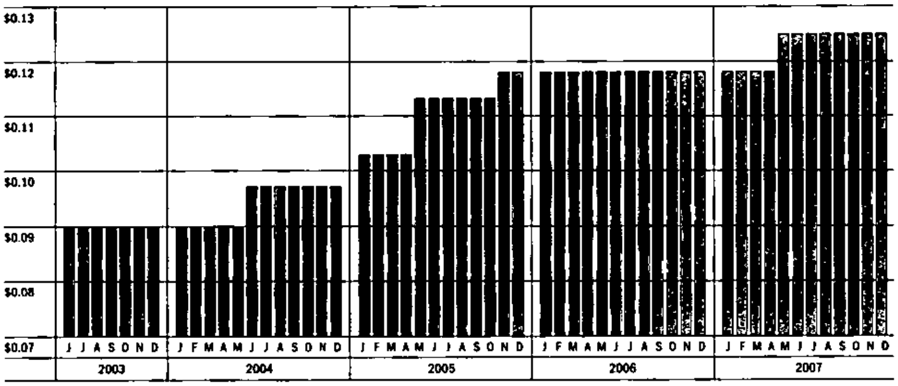
Quarterly Cash Flows
($ per unit)

▨ Cash Distributions

■ Distributable Cash Flow[1]

* Partial period May 30 – June 30

[1] Distributable cash flow is not a standard measure under Canadian generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures reported by other entities. The most comparable GAAP measure to distributable cash flow is cash flow from operating activities. A reconciliation between distributable cash flow and cash flow from operating activities can be found on page 22 of Keyera's 2007 Financial Report.



Monthly Distribution History
($ per unit)

2008 Key Dates

January
15 December distribution paid
29 January ex-distribution date
31 January record date

February
15 January distribution paid
26 2007 year end results
27 2007 year end conference call
27 February ex-distribution date
29 February record date

March
17 February distribution paid
27 March ex-distribution date
31 March record date

April
15 March distribution paid
28 April ex-distribution date
30 April record date

May
13 First quarter results
13 Annual meeting of unitholders
14 First quarter conference call
15 April distribution paid
28 May ex-distribution date
30 May record date

June
16 May distribution paid
26 June ex-distribution date
30 June record date

July
15 June distribution paid
29 July ex-distribution date
31 July record date

August
12 Second quarter results
13 Second quarter conference call
15 July distribution paid
27 August ex-distribution date
29 August record date

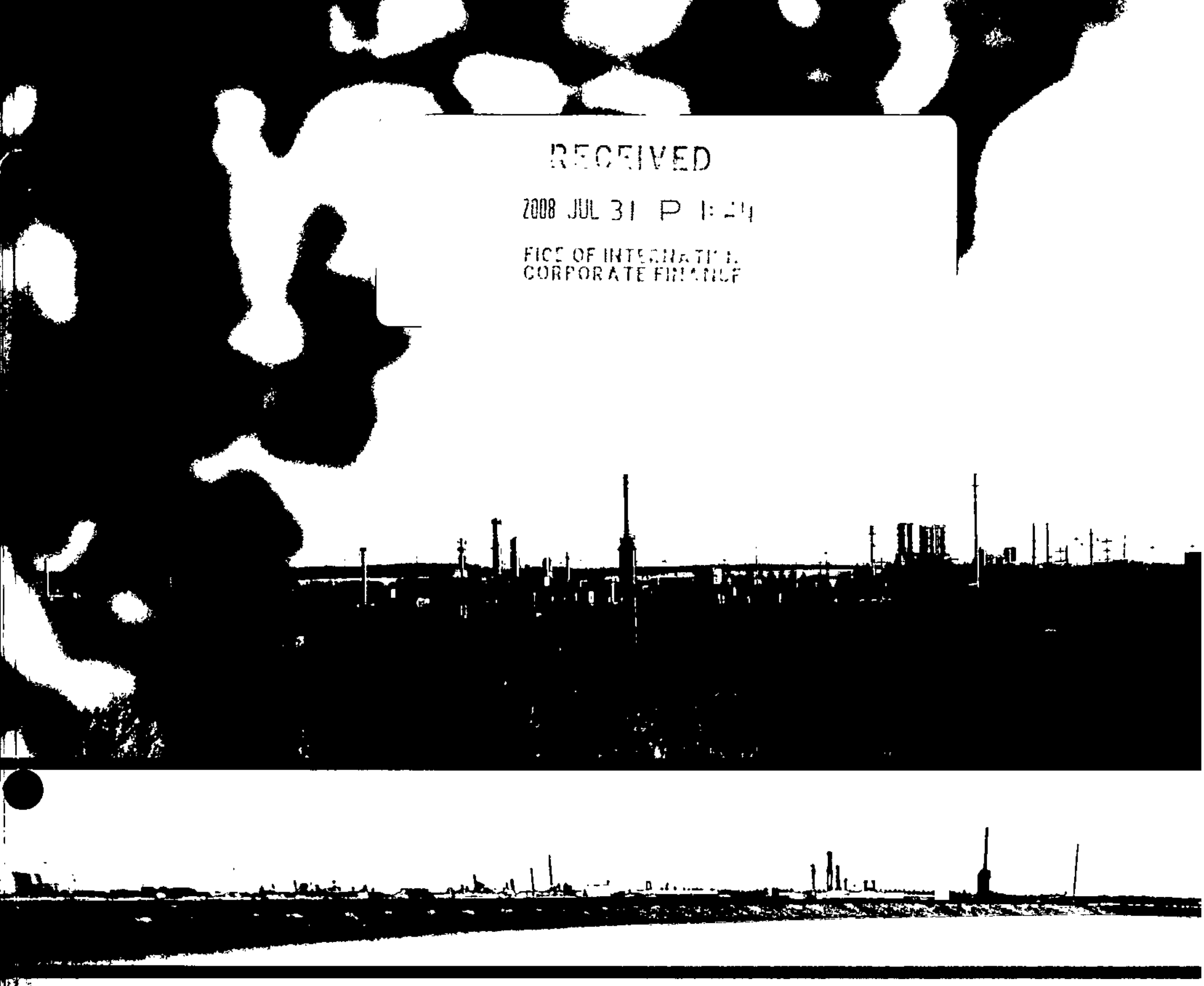
September
15 August distribution paid
26 September ex-distribution date
30 September record date

October
15 September distribution paid
29 October ex-distribution date
31 October record date

November
10 Third quarter results
11 Third quarter conference call
17 October distribution paid
26 November ex-distribution date
28 November record date

December
15 November distribution paid
29 December ex-distribution date
31 December record date

KEYERA
www.keyera.com



2007 Financial Report

KEYERA

Ahead of the Curve

Investing for long-term value

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; processing, transportation and storage of natural gas liquids (NGLs) and crude oil; and NGL marketing and crude oil midstream services.

Our gathering and processing facilities are strategically located in natural gas production areas on the western side of the Western Canada 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.

Notice to Readers

This 2007 Financial Report contains forward looking information, which is based on management's current beliefs and assumptions. Actual events or results may differ materially. For further information, please refer to the advisory on page 2.

Inside

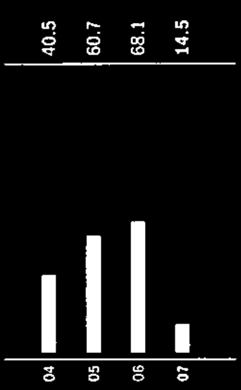
Keyera trades on The Toronto Stock Exchange under the symbols KEY.UN and KEY.DB.

KEYERA

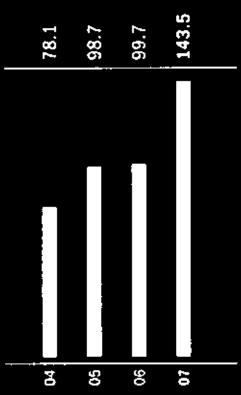
About the cover: Located in Alberta's Industrial Heartland alongside the North Saskatchewan River, Keyera's Fort Saskatchewan NGL fractionation and storage facility is well positioned to provide services to the evolving oil sands sector in Alberta.

Financial Highlights

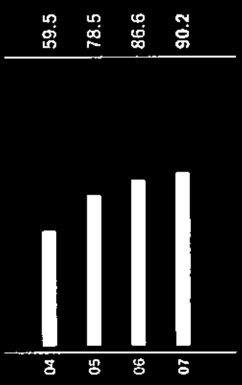
	2007	2006	2005	2004[2]
Revenues ($ millions)	1,479.1	1,368.5	1,187.6	937.4
Net earnings ($ millions)	14.5	68.1	60.7	40.5
Capital expenditures ($ millions)	32.0	73.9	52.9	29.8
Distributable cash flow[1] ($ millions)	143.5	99.7	98.7	78.1
Per unit ($)	2.35	1.65	1.67	1.50
Distributions to unitholders ($ millions)	90.2	86.6	78.5	59.5
Per unit ($)	1.48	1.43	1.33	1.14



Net Earnings
($ millions)



Distributable Cash Flow[1]
($ millions)



Distributions to Unitholders
($ millions)

Ahead of the curve reflects Keyera's entrepreneurial spirit. It reflects a proactive approach to operating our assets, anticipating the needs of our customers, capturing new opportunities, managing risks and growing our business. From regular, preventative maintenance of our facilities to emergency response planning, from projects that support producer initiatives to health, safety and environmental stewardship, Keyera is **Ahead of the curve**.

---

[1] See Note Regarding Non-GAAP Financial Measures on page 2. Distributable cash flow is not a standard measure under Canadian generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures reported by other entities. The most comparable GAAP measure to distributable cash flow is cash flow from operating activities. A reconciliation between distributable cash flow and cash flow from operating activities can be found on page 22.

[2] 2004 reflects Keyera Energy Partnership results and is included for comparison purposes. 2004 distributable cash flow is shown before deducting Fund expenses.

Management's Discussion & Analysis

The following management's discussion and analysis ("MD&A") was prepared as of February 26, 2008 and is a review of the results of operations and the liquidity and capital resources of Keyera Facilities Income Fund (the "Fund") and its subsidiaries (collectively "Keyera"). It should be read in conjunction with the accompanying audited consolidated financial statements of the Fund for the year ended December 31, 2007 and the notes thereto. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and are stated in Canadian dollars. Additional information related to the Fund, including the Fund's Annual Information Form, is filed on SEDAR at www.sedar.com.

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"). Measures such as operating margin (operating revenues minus operating expenses), distributable cash flow (cash flow from operating activities adjusted for changes in non-cash working capital, maintenance capital expenditures and the distributable cash flow attributable to any non-controlling interest) and EBITDA (earnings before interest, taxes, depreciation and amortization) are not standard measures under GAAP and therefore may not be comparable to similar measures reported by other entities. Management believes that these supplemental measures facilitate the understanding of the Fund's results of operations, leverage, liquidity and financial position. Operating margin is used to assess the performance of specific segments before general and administrative expenses and other non-operating expenses. Distributable cash flow is used to assess the level of cash flow generated from ongoing operations and to evaluate the adequacy of internally generated cash flow to fund distributions. EBITDA is commonly used by management, investors and creditors in the calculation of ratios for assessing leverage and financial performance. 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. In some instances, this MD&A and accompanying documents may also contain forward-looking statements attributed to third party sources. For example, the discussions with respect to possible amendments to federal legislation imposing taxes on the distributions of publicly traded income trusts and partnerships and the proposed changes in the Alberta royalty system are based solely on news releases and background information prepared by the federal and Alberta governments respectively. Management believes that its assumptions and analysis in this MD&A 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 Annual Information Form dated February 26, 2008 (the "Annual Information Form") filed on SEDAR and available on the Keyera website at **www.keyera.com**.

Readers are cautioned that they should not unduly rely on the forward looking statements in this MD&A and accompanying documents. Further, readers are cautioned that the forward looking statements in this MD&A 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 SEDAR at **www.sedar.com**.

Business Environment

Industry Activity

In 2007, producers drilled 18,606 wells in Canada, down from the record levels of activity experienced over the last several years and 20% lower than in 2006. Drilling activity was affected by a number of factors, including low gas prices, high costs and a number of government regulatory and fiscal changes.

Despite this slowdown in activity levels, throughput at Keyera facilities increased by 3% compared to 2006. This increase partially reflects the tie-in of wells drilled in earlier years, but also reflects a more selective approach to exploration and development efforts by producers. Customers have indicated that they are choosing drilling locations that are close to existing infrastructure, allowing them to connect their production quickly. Often the gas reserves are rich in NGLs, resulting in higher producer netbacks.

In the fourth quarter, producers in Canada drilled almost 5,300 wells, down slightly from the third quarter of 2007, and down just 4% from the same period last year. On a go forward basis, the Petroleum Services Association of Canada is forecasting a similar number of wells to be drilled in the first quarter of 2008 as were drilled over the past two quarters.

In the foothills front region of Alberta, the number of wells drilled in the fourth quarter was 16% less than the fourth quarter of 2006. The average depth of wells drilled in this region in the fourth quarter was 2,144 metres, 11% lower than the same period last year. In the central Alberta region, the number of wells drilled was 20% lower than the same quarter last year, with the average depth per well remaining flat at 1,131 metres. British Columbia also experienced a decline in drilling, with wells drilled falling 5% compared to the fourth quarter of last year. The average depth per well in this area increased to over 2,300 metres, a 9% increase in depth compared to the fourth quarter of 2006.

Throughput volumes at most Keyera plants increased again in the fourth quarter, with overall throughputs up 6% compared to the third quarter of 2007 and up 9% from the fourth quarter of 2006. Producer activity around Keyera's plants, combined with Keyera's growth projects, were responsible for the increase.

Indications are that North American natural gas fundamentals may be strengthening. Recent North American natural gas demand has been strong and U.S. natural gas storage inventories are at their lowest level for this time of year since early 2005. The U.S. Energy Information Administration estimates that, if the U.S. has normal weather for the remainder of the winter, U.S. inventories will end the winter at normal levels, more than 20% below last year's end-of-winter levels. Keyera believes that these positive trends support continued drilling activity in western Canada, particularly on the western side of the basin where most of its facilities are located.

New Alberta royalty framework

On October 25, 2007 the Government of Alberta announced increases in royalties. The new royalty regime, which is expected to be implemented in 2009, will change the royalty structure for natural gas and conventional oil by adjusting sliding rate formulas that are price and volume sensitive. These changes result in higher royalty rates at current prices. In addition, new price sensitive formulas will be adopted for oil sands development at both the pre- and post-payout stages.

Keyera is not a royalty payor, and therefore is not directly affected by the proposed royalty changes. However, as a service provider to the upstream industry, Keyera will be affected by producers' responses to the new regime. Producers are continuing to assess the impact of the new royalty regime on their operations and future activities. Keyera is working with producers in the areas around its plants to determine what impact the proposed royalty changes may have on Keyera. Until we have stronger indications from producers with respect to their plans, the long term implications of the royalty announcement for Keyera are difficult to determine. Since many of Keyera's facilities are located west of the fifth meridian where gas drilling tends to be deeper, the Government's decision to retain a variation of the Deep Gas Drilling Program is a positive outcome for Keyera.

Further information about the new royalty framework is available from the Government of Alberta website at **www.gov.ab.ca** and a copy of the framework itself can be found at **www.energy.gov.ab.ca/Org/Publications/royalty_Oct25.pdf.**

Climate change regulations

In 2007, the Alberta government amended laws and regulations dealing with greenhouse gas emissions. The initiative is designed to reduce the emissions intensity (i.e. the amount of greenhouse gases emitted on a unit of production basis) of greenhouse gases at applicable facilities.

Under the new rules, existing large emitters must reduce net emissions intensity to 88% of the average emissions intensity at a facility between 2003 and 2005. If the actual emissions intensity is above the target, the facility licensee can generate or purchase "emissions offsets", or purchase fund credits at a cost of $15/tonne of CO_2 equivalent, or purchase emission "performance credits".

Keyera operates three facilities which are subject to these requirements: the Strachan, Rimbey and Brazeau River gas plants. Based on a worst case scenario, which assumes that Keyera purchases fund credits at $15/tonne and no offsets or credits are created or purchased at a cost that is less than $15/tonne, the anticipated cost of these new rules for Keyera is estimated at $408,000 in 2007. Thereafter, on an annual basis, the cost is expected to be approximately $1 million per year. Keyera's management anticipates that a portion of these costs will be recoverable from customers as flow-through operating costs. Projects implemented since 2002 at Keyera's facilities could generate emissions offsets or performance credits; however, it is premature to determine what benefit, if any, could be realized from such actions.

In January 2008, the Alberta government announced its intention to reduce projected greenhouse gas emissions in Alberta by 50% by 2050. No details of this initiative are currently available.

The federal government released the *Regulatory Framework for Air Emissions* (the "Framework") on April 26, 2007 which sets out new GHG and air pollutant ("AP") emission reduction targets for various industrial sectors, including the oil and gas industry. The Framework forms the basis for consultations and the draft GHG and AP regulations are expected to be released in the spring of 2008. The effect on Keyera can not be determined until the federal government provides additional information.

As part of the provincial budget brought down on February 19, 2008, the B.C. government announced a proposed broad-based carbon tax to be implemented effective July 1, 2008. According to the budget, the carbon tax initially will not apply to industrial emissions, including emissions from the oil and gas industry. The budget does not provide a timeframe for extension of the tax to industrial emissions. The effect on Keyera can not be determined until the B.C. government provides additional information.

Other environmental regulations

On October 2, 2007, the Government of Alberta announced a new cumulative effects initiative covering the "industrial heartland" area northeast of Edmonton. This initiative establishes targets for air, water and land quality and applies to all large industrial facilities within the area, including Keyera's Fort Saskatchewan facility. These facilities will be subject to cumulative airshed targets which are scheduled to come into effect in January 2009. Working groups have been or are being formed to deal with the allocation of the airshed objectives, water and land management issues, including sulphur and wetlands management. Based on the information currently available, Keyera does not anticipate that this initiative will require significant changes to current operations. However, the effect that this program may have on future operations or possible expansion is not clear at this time. A more complete description of the environmental regulations that affect Keyera's businesses can be found in the Annual Information Form, which is available on Keyera's website at **www.keyera.com** or on SEDAR at **www.sedar.com**.

Tax changes

In October 2006, the Government of Canada announced a new tax on the distributed income of publicly-traded Canadian income trusts and limited partnerships (the "Distribution Tax"), and in June of 2007, implementing legislation was passed. So long as Keyera only experiences "normal growth", the Fund will not be subject to the Distribution Tax until January 2011. As a result, beginning in 2011, tax will be payable by Keyera on the portion of its distributions that is considered ordinary taxable income and, for a Canadian resident taxpayer, this portion of Keyera's distributions will be treated as dividend income for tax purposes. There will be no change in the taxation of Keyera's distributions that are considered to be a return of capital or dividend income.

On October 30, 2007, the Federal government announced a proposal to reduce federal corporate tax rates from 22.12% in 2007 to 15% by 2012. These lower tax rates would also apply to income trusts. These tax measures became law on December 14, 2007 reducing the combined federal and provincial tax rate that will be applicable to the Fund from 31.5% to 29.5% in 2011 and 28% in 2012. This reduction in federal tax rates has been included in the determination of the future tax provision of the Fund.

On December 20, 2007, the federal department of finance proposed amendments to clarify the Distribution Tax legislation. These proposals included technical amendments to allow a trust or partnership to hold a diversified portfolio investment through one or more "portfolio investment entities" without causing the trust or partnership to be subject to the Distribution Tax. Once the proposed amendments are passed, Keyera may consider a further re-organization.

The Distribution Tax will reduce the amount of cash flow available to Unitholders. Keyera's management and Board of Directors considers this future reduction in cash flow in their distribution decisions.

As at January 1, 2008, Keyera estimates that it has approximately $325 million of unutilized tax pools and deductions, consisting mostly of class 41 undepreciated capital costs, available for deduction by the Fund's subsidiaries.

Results of Operations

Keyera's 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 Annual Information Form, which is available on Keyera's website at **www.keyera.com** or on SEDAR at **www.sedar.com**.

Keyera delivered exceptional financial results in 2007, with operating margin of $179.1 million, $33.1 million higher than in 2006. These record results were achieved despite a slowdown in the oil and gas industry in western Canada and the completion of maintenance turnarounds at the Rimbey gas plant, Keyera's largest facility, as well as at the Brazeau River, Bigoray and Medicine River gas plants.

All business segments contributed to these results, with each business segment achieving record performance. A number of Keyera's gas plants in the Gathering and Processing segment saw throughputs increase in 2007, resulting in overall throughput reaching the highest levels in Keyera's history. Storage revenues in the NGL Infrastructure segment continued to grow and strong market fundamentals combined with Keyera's access to proprietary rail infrastructure and logistical expertise enabled the Marketing segment to post record results.

This strong operating performance in 2007 was partially offset by a non-cash future income tax expense of $72.6 million. This was primarily related to the income trust tax legislation enacted in the second quarter of 2007, partially offset by a $11.7 million future income tax recovery in the fourth quarter resulting from the enactment in December 2007 of lower federal income tax rates. As a result of the non-cash future income tax expense, together with slightly higher general and administrative costs, interest expense and depreciation charges, net earnings and comprehensive income was $14.5 million in 2007, compared to $68.1 million in 2006.

Consolidated net earnings for the fourth quarter of 2007 were $40.0 million, up $25.1 million from the same period in 2006. The strong operating margin earned from all segments and the $11.7 million non-cash future income tax recovery, partially offset by higher general and administrative and interest costs, accounted for the increase. The non-cash future income tax recovery resulted from the enactment of lower federal income tax rates in December 2007.

Gathering and Processing

Gathering and Processing revenue for 2007 was $187.5 million, an increase of $20.8 million, or 12%, compared to the previous year. The increase was due primarily to higher throughput in the Foothills Region, the recovery of a portion of turnaround costs incurred at the Rimbey, Brazeau River, Bigoray and Strachan gas plants, the conversion from fixed to flow-through fees at certain plants and incremental compression fees at the Rimbey gas plant in 2007.

In the fourth quarter of 2007, Gathering and Processing revenue was $50.5 million, an increase of $6.9 million, or 16%, compared to the same period in 2006. The increase was primarily due to higher throughput in the Foothills Region and the commencement of reprocessing services at the Paddle River gas plant.

Gathering and Processing operating expenses for 2007 were $103.8 million, an increase of $7.2 million, or 7%, compared to 2006. The increase was primarily due to higher turnaround costs for the turnarounds completed in 2007 at the Rimbey, Bigoray, Brazeau River and Medicine River gas plants, compared to the turnaround costs incurred in 2006. Another factor in the increase was higher operating costs at Caribou resulting from higher throughput and unscheduled maintenance work at the plant.

In the fourth quarter of 2007, Gathering and Processing operating expenses were $24.1 million, an increase of $1.8 million compared to the same period in 2006. The increase was primarily a result of higher operating and maintenance costs at the Strachan gas plant due to higher volumes and maintenance work completed in the quarter.

Average gross processing throughput in 2007 was 843 million cubic feet per day, a new record and 3% higher than 2006. Fourth quarter throughput of 882 million cubic feet per day was up 9% from the same period in 2006.

During 2007, Keyera's Gathering and Processing assets were realigned into new business regions, the Foothills Region and the North Central Region. The Foothills Region consists of the Strachan, Brazeau River, Nordegg River, Paddle River, Bigoray, Brazeau North, West Pembina and Tomahawk gas plants and associated gathering pipelines. The North Central Region consists of the Rimbey, Gilby, Medicine River, Worsley, Caribou, Chinchaga, North Star and Greenstreet gas plants and associated gathering pipelines. This realignment is reflected in the discussion below.

Gathering and Processing – North Central Region

The North Central Region posted very strong results in 2007, despite a slowdown in shallow drilling activity in the region and the completion of a scheduled turnaround at the Rimbey gas plant, Keyera's largest facility. Gross throughput of 432 million cubic feet per day in 2007 was 6% lower than last year, resulting from the loss of processing throughput while the Rimbey turnaround was underway and lower drilling activity in the Rimbey/Gilby area. In the fourth quarter of 2007, throughput was 440 million cubic feet per day, 3% lower than the same period last year. The decline was a result of lower drilling activity in the Rimbey/Gilby area.

In the Rimbey/Gilby region, the loss of throughput resulting from a slowdown in drilling was offset by tie-ins of previously drilled wells. Keyera has been encouraged by current drilling activity in this area and has identified a number of additional opportunities to offset any further declines. Rimbey is an attractive processing alternative for producers, offering higher netbacks resulting from Rimbey's ability to deliver specification NGL products, as well as other products and services. Volumes delivered to the NGL offload facility at Rimbey increased in 2007.

In the Caribou region, activity continued in both new well licenses and land sales throughout the year. Keyera extended the Caribou North Gas Gathering System in early 2007 across the Trutch Creek at the north end of the pipeline, to connect production from new gas drilling in that area. At mid year, Keyera acquired about 18 kilometres of existing gathering pipeline and an abandoned plant site north of the existing pipeline system and, at year end, announced a further 24-kilometre extension of the Caribou North Gas Gathering pipeline. Throughput is now averaging 50 million cubic feet per day at Caribou, about 75% of capacity, and detailed engineering is underway for a possible expansion of the facility.

In July 2007, Keyera announced a project at the Rimbey gas plant to extract ethane from the raw gas at the plant. The proposed project, estimated to cost $26 million, involves modifying the existing NGL extraction process and installing new compression equipment at the plant and constructing a 32-kilometre ethane delivery pipeline. The project is awaiting regulatory approval from the Energy Resources

Conservation Board. If approved Keyera will be able to extract up to 5,000 barrels per day of saleable ethane from field gas processed at the Rimbey plant. A significant portion of the ethane to be extracted is currently used as fuel gas within the plant and will therefore be incremental to the current supply of ethane in Alberta.

In January 2008, the North Star gas plant, a non-core asset, was sold.

Gathering and Processing – Foothills Region

The Foothills Region delivered record results in 2007, as continued strong drilling activity in the region resulted in increasing throughput during the year. Gross throughput of 411 million cubic feet per day in 2007 was 51 million cubic feet per day, or 14%, higher than in 2006. In addition, Foothills revenues benefited from higher fees due to the higher concentrations of NGLs and hydrogen sulphide in the gas streams. In the fourth quarter of 2007, throughput was 442 million cubic feet per day, 25% higher than the same period in 2006. This increase was due to significant producer activity around Foothills Region plants.

In the Pembina area, sour gas development targeting the Nisku zones continued in the fourth quarter, including the licensing of several new wells. Utilization at Keyera's three sour gas processing plants in the area, Bigoray, West Pembina and Brazeau River, continued to increase throughout the year. To address the resulting sour gas capacity constraints, Keyera completed modifications to its pipeline systems in the fourth quarter to increase processing flexibility by diverting sour gas to other plants in the area.

A pressure survey of the acid gas disposal well at the Brazeau River gas plant was completed while the plant was offline for its scheduled maintenance turnaround. The survey indicated that the acid gas reservoir was filling more rapidly than anticipated. In the fourth quarter, Keyera acquired a depleted reservoir as well as another acid gas injection well. Construction of the necessary pipeline connections began early in the new year and the well became operational in February 2008. Until the new well was operational, some volumes were redirected to other Keyera facilities for processing and, for a brief period, sour gas processing was curtailed at the Brazeau River gas plant.

At the Bigoray gas plant, piping and equipment modifications were completed earlier in 2007 to provide for the future expansion of sour gas processing at the plant. In addition, a new distributed control system was installed at the plant to provide improved operating reliability and flexibility. Throughput increased substantially during the year and Keyera is currently working on plans to debottleneck gathering and inlet compression facilities to accommodate the increasing production volumes.

Lands to the west of Keyera's Strachan, Nordegg River and Brazeau River gas plants saw considerable activity throughout the year as producers pursued sweet, liquids-rich plays. These areas are close to Keyera gathering pipelines and processing infrastructure, enabling quick tie-ins and production. In addition, the liquids-rich gas provides the producer with a higher netback than dry sweet gas, making these play types attractive to producers.

New production was connected to the Strachan North pipeline for delivery to the Strachan gas plant in the fourth quarter. A producer-owned field compressor was installed during the fourth quarter, resulting in increased throughput at Strachan. Southwest of the Brazeau River gas plant, Keyera is partnering with a producer to build a new gathering pipeline to deliver new gas production to the plant. The pipeline is expected to be operational late in the first quarter.

In the fourth quarter, Keyera entered into an arrangement to use its NGL extraction facilities to extract NGLs from new gas volumes delivered to the Paddle River gas plant.

NGL Infrastructure

NGL Infrastructure revenue for 2007 was $41.1 million, an increase of $1.2 million, or 3%, compared to the previous year. The increase was primarily due to higher storage revenues at Keyera's Fort Saskatchewan facility. The effect of higher storage revenues was partly offset by a fee adjustment and reduced volumes from the Rimbey Pipeline system in the third quarter of 2007.

NGL Infrastructure operating expenses for 2007 were $24.3 million, an increase of $0.3 million compared to 2006. This increase was largely due to higher supplies and maintenance costs partly offset by lower costs for electricity and natural gas.

In the fourth quarter of 2007, NGL Infrastructure revenues were $1.0 million higher than the same period in 2006, largely due to higher storage revenues at the Fort Saskatchewan facility. Operating expenses were $0.5 million higher than the fourth quarter of 2006, due primarily to the purchase of an additional charcoal bed filter.

NGL Infrastructure facilities overall operated at typical levels for the fourth quarter. Higher product demand, particularly for propane, and the receipt of imported condensate resulted in higher rail loading activity in the fourth quarter. Storage revenues remained strong in the fourth quarter, driven by normal winter season inventory requirements and diluent demand for oil sands production. Fractionation throughput was lower than usual in the third quarter of 2007 due to short-term market conditions, but returned to typical levels in the fourth quarter.

Keyera continues to focus on strengthening its competitive position in the Edmonton/Fort Saskatchewan area. As part of that strategy, Keyera is pursuing a number of initiatives.

Work is underway to expand the storage capacity at Keyera's Fort Saskatchewan facility to meet the expected need for diluent storage to support oil sands development over the next decade. The project, which is expected to take five to six years to complete, will expand the current storage capacity by three million barrels, or 37%, to about 11.6 million barrels and is expected to cost $70 to $80 million. Engineering work on the first cavern is being finalized, equipment is being ordered and site construction work was completed early in the first quarter of 2008. The cost of the first cavern is expected to be $18 million, with a large portion of the cost being spent in 2008. Assuming construction proceeds as planned, the first cavern is expected to be put into service late in 2009.

The expansion of the truck terminal at the Fort Saskatchewan facility is largely complete, commissioning will begin shortly and the facility is expected to be operational in March. The project will increase Keyera's operational flexibility and provide enhanced product loading services for customers serving the domestic NGL market.

The fourth pipeline between the Fort Saskatchewan facility and the Edmonton terminal is also proceeding and is expected to be onstream by mid-year assuming timely receipt of land owner approval. Engineering work on this project has identified additional operational efficiencies which have provided a capacity boost, eliminating the need for a booster station on the pipeline and reducing the net capital cost of the project. When operational, the new pipeline will provide significantly more operational flexibility, allowing Keyera to deliver condensate and butane at increased rates into and out of the Edmonton terminal, Fort Saskatchewan storage and other pipelines and terminals in the area. This pipeline is also expected to support the new storage caverns and will add value to Keyera's storage services by increasing the flexibility for customers.

Looking to the future, Keyera is working towards connecting the Fort Saskatchewan and Edmonton facilities to more pipelines and new facilities in the area. In the first quarter of 2008, Keyera reached an agreement with a major pipeline operator to connect Keyera's facilities into another major crude oil, condensate and NGL pipeline delivering product into the Edmonton/Fort Saskatchewan hub.

Marketing

Generally, market fundamentals for propane, butane and condensate were positive throughout the year as supply and demand remained largely in balance and rising crude oil prices positively affected product prices. Keyera exploited these strong fundamentals throughout the year and utilized its proprietary rail and storage infrastructure to enhance unit margins.

Marketing revenue for 2007 was $1,250.5 million, an increase of $88.6 million compared to the previous year. The increase was due primarily to higher sales prices and growth in the crude oil midstream business, partially offset by the cost of the financial contracts that Keyera uses in its risk management program. Keyera's risk management program employs a multi-faceted approach to managing its supply and sales portfolio, including: monitoring its inventory position and its purchase and sale commitments; actively participating in various hub markets; using financial contracts, such as energy-related forward sales, price swaps, physical exchanges and options; and offsetting some of its physical and financial contracts in terms of volumes, timing of performance and delivery obligations. (See "Liquidity and Capital Resources – Marketing Risk Management"). Due to rising prices for crude oil and liquid hydrocarbons in 2007, the forward financial sales contracts used to hedge the commodity price risk arising from holding physical inventory reduced marketing revenues by $20.0 million, while in 2006 the program added $7.0 million in revenues due to declining commodity prices.

The table below outlines 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

(Thousands of Canadian dollars)	Twelve months ended December 31, **2007**
Physical sales	**1,270,511**
Financial instruments – realized	**(10,059)**
Financial instruments – unrealized	**(9,911)**
Marketing revenue	**1,250,541**

Changes in Fair Value of Energy Derivative Contracts

(Thousands of Canadian dollars)	
Fair value at December 31, 2006	211
Change in the fair value of contracts	9,848
Fair value of new contracts entered into in 2007	(9,911)
Realized losses	(10,059)
Fair value at December 31, 2007 [1]	**(9,911)**

[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, 2007.*

NGL sales volumes for 2007 averaged 50,800 barrels per day compared to 52,200 barrels per day in 2006. The reduction was a result of lower propane volumes in 2007, partially offset by growth in butane and condensate volumes. In the fourth quarter of 2007, NGL sales volumes averaged 53,800 barrels per day compared to 55,400 barrels per day in the fourth quarter of 2006.

Marketing operating expenses for 2007 were $1,172.0 million, an increase of $70.0 million compared to the previous year. The increase was due primarily to higher supply costs compared to 2006.

NGL product inventories of $76.6 million at December 31, 2007 were $22.7 million higher than the previous year due to higher volumes and significantly higher prices at year-end. Inventory has been valued at the lower of cost or net realizable value at December 31, 2007.

Propane demand in 2007 followed normal seasonal trends. In the first quarter, cold weather bolstered demand and Keyera used its rail car fleet and NGL infrastructure to facilitate the movement of product to niche markets where demand and prices were high. The second and third quarters experienced lower demand, typical of the summer season. The fourth quarter saw a seasonal increase in demand early in the quarter and prices remained high due to the strong correlation with the price of crude oil. Keyera used the propane terminal in Superior, Montana, which was acquired in June of 2007, as well as its other three propane terminals in the US, to deliver propane into regional markets via rail car for loading onto customers' trucks for further delivery to end use customers.

Butane demand remained strong throughout most of 2007, which enabled Keyera to earn steady margins from quarter to quarter. Much of Keyera's supply was committed to term sales contracts, providing a steady market for product and secure margins.

In general, condensate demand was strong throughout most of 2007, as oil sands producers continued to purchase condensate for use as diluent to enable heavier crude oil to flow in pipelines. Keyera imported condensate into Alberta from lower priced regions in North America throughout the year, using its storage facilities at Fort Saskatchewan to exploit periods of short-term price volatility. In addition, Keyera used its newly constructed condensate truck loading rack at the Rimbey gas plant to deliver product into local markets. The utilization of its asset infrastructure was a key factor in allowing Keyera to deliver strong condensate margins throughout the year.

Keyera's crude oil midstream business continued to develop in 2007. Market fundamentals were strong throughout the year, enabling the business to contribute increased operating margins compared to 2006.

In the fourth quarter of 2007, marketing revenues of $373.9 and operating expenses of $352.4 million generated $21.5 million of operating margin, up $9.7 million from the same period in 2006. This increase was related to several factors. Product prices were stronger in 2007 compared to 2006 when, in the fourth quarter of the year, warm weather in the eastern U.S. contributed to lower propane demand and butane and condensate markets remained soft. In the fourth quarter of 2007, prices for all products were influenced by high crude oil prices. Propane demand was typically strong for the winter season, butane term sales provided steady margins and condensate was in high demand for use as diluent. All of these factors contributed to sound unit margins. Adjustments relating to the routine voidance of a butane cavern in the fourth quarter of 2007 reduced margins by $0.8 million.

At December 31, 2007, the unrealized loss on financial contracts recognized in the fourth quarter was $1.7 million ($12.0 million recognized for the full year), primarily due to the change in the value of crude oil price swap contracts and fixed price contracts. At December 31, 2007, the fair market value of these contracts represented a liability of $12.4 million and an asset of $2.5 million, which represents an estimate of the amount that Keyera would pay or receive if these instruments had been closed out at the end of the period. The estimated fair value of all derivatives held for trading is based on quoted market prices and, if not available, on estimates from third party brokers or dealers.

Of the $12.0 million unrealized loss in 2007, the portion relating to changes in crude oil financial contracts amounted to approximately $9.9 million. These contracts are used to protect inventory from fluctuations in the prices of NGL products. To the extent these contracts are effective (i.e., the change in the market price of crude oil is correlated to the change in the prices of the underlying physical NGL products), gains and losses on these financial contracts will be offset by gains and losses in the proceeds that will be realized upon the sale of the products.

The remainder of the 2007 unrealized loss relates primarily to the $2.3 million unrealized loss recognized in the first quarter of 2007 as a result of the adoption of new accounting standards for fixed price physical contracts. As the fixed price contracts were priced higher than market, the new accounting standards required an asset of $2.3 million to be recorded with a corresponding decrease in opening deficit. As these contracts matured and the actual proceeds on the fixed price sales were recorded in revenue, the previously recorded asset of $2.3 million was reduced to nil with a corresponding charge (unrealized loss) to earnings in the first quarter of 2007.

The adoption of the new accounting standards is expected to continue to result in volatility in operating margins due to unrealized gains and losses associated with financial instruments.

Non-operating Expenses and Other Earnings

General and administrative expenses for 2007 were $21.9 million, up $3.0 million from the previous year. Long-term incentive plan costs were $3.2 million higher than in 2006, reflecting an increase in unit price and the effect of a distribution increase implemented in May 2007. Excluding the effect of the long-term incentive plan, general and administrative expenses were in line with those incurred in 2006.

Interest expense, net of interest revenue, was $20.2 million for 2007, $2.0 million greater than in 2006. The increase was due to higher borrowings used to fund capital projects undertaken in 2006 and 2007.

Depreciation and amortization expense was $42.0 million for 2007, $2.2 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 two years.

An impairment expense of $0.7 million was recorded in 2007 to adjust the carrying value of the North Star gas plant, a small non-core facility that was sold in early 2008.

Income tax expense for 2007 was $77.0 million, $79.7 million higher than the previous year due to an increase in future income tax expense. Future income tax expense for 2007 was $72.6 million compared with a future income tax recovery of $7.0 million in the prior year. This increase was primarily due to recording $80.2 million of future income tax expense in the second quarter of 2007 resulting from the new tax imposed on publicly traded income trusts and limited partnerships in Canada. The future tax expense is an estimate of the tax that will ultimately be payable by the Fund due to differences between the accounting and tax basis of assets and liabilities of the operating partnership. As a result of the new tax legislation, distributions will no longer be deductible by the Fund beginning in 2011. The effect of recording the new tax on income trusts was partially offset by lower future federal income tax rates that were enacted in 2007.

Current income tax expense for 2007 was $4.3 million, virtually unchanged from 2006. The impact of lower earnings posted by the Rimbey Pipeline business in the third quarter of 2007 was offset by higher earnings posted by Keyera Energy Facilities Ltd. throughout 2007.

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, 2007, operating revenues and accounts receivable for the Gathering and Processing and NGL Infrastructure segments contained an estimate of $21.8 million primarily for December 2007 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, 2007, operating expenses and accounts payable contained an estimate of $8.5 million primarily for December 2007 operations.

Estimation of Gathering and Processing and NGL Infrastructure equalization adjustments:

Much of the revenue from the Gathering and Processing and NGL Infrastructure assets includes a recovery of operating costs. 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 $6.6 million at December 31, 2007. Operating expenses and accounts payable contained an estimate of $6.9 million.

Estimation of Marketing revenues:

The majority of the Marketing sales revenues is 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, 2007, the Marketing sales and accounts receivable contained an estimate for December 2007 revenues of $75.7 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 $101.3 million at December 31, 2007.

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 lives. 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, 2007, the total undiscounted amount required to settle the asset retirement obligations is $183.0 million, compared to $183.2 million at December 31, 2006. The discounted net present value of this obligation at December 31, 2007 is $37.8 million, compared to $34.5 million at December 31, 2006. The increase in the discounted amount is primarily due to accretion.

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 2008 Annual Information Form, which is available on SEDAR.

Liquidity and Capital Resources

Cash Flow from Operating Activities

Cash flow from operating activities during the fourth quarter of 2007 was $45.5 million, of which $3.9 million was generated from a decrease in non-cash working capital. Before changes in non-cash working capital, cash flow from operating activities was $41.6 million. From this cash flow, Keyera paid $23.0 million of distributions to its unitholders and required $8.4 million for capital expenditures, leaving $10.2 million of cash. Keyera also received $39.6 million of net proceeds from the issuance of long-term debt, $0.8 million from the issuance of trust units under the distribution reinvestment plan ("DRIP"), $3.9 million from the change in non-cash working capital and $0.5 million of proceeds from the disposition of equipment. From this cash, Keyera repaid $40.0 million of short-term borrowings, leaving a net cash inflow of $15.0 million for the quarter.

For the full year, cash flow from operating activities was $119.8 million, after the use of $25.5 million to fund an increase in non-cash working capital primarily due to higher product inventories. Cash flow from operating activities before changes in non-cash working capital was $145.3 million. From this cash flow Keyera paid $89.8 million of distributions to its unitholders and required $33.1 million for capital expenditures and acquisitions, leaving $22.4 million of cash. Keyera also received $4.7 million from dispositions and $3.3 million from the issuance of trust units under the DRIP, bringing cash available to $30.4 million. Along with this cash, net proceeds of $118.9 million from the issuance of long-term debt were used to fund the repayment of $108.0 million of short-term borrowings and finance the $25.5 million change in non-cash working capital, leaving a $15.8 million net cash inflow for the year.

Cash and working capital were $75.7 million at December 31, 2007 compared to a deficit of $41.1 million at December 31, 2006. The deficit at December 31, 2006 resulted from the use of short-term debt to finance growth capital expenditures and was eliminated in 2007 when Keyera received $118.9 million of net proceeds from the issuance of long-term debt and used much of these proceeds to repay short-term debt.

Keyera has no direct exposure to asset backed commercial paper. Surplus cash is held in interest bearing deposit accounts or invested in term deposits, guaranteed investment certificates, or Bankers' Acceptances issued by Canadian chartered banks.

Capital Expenditures

Captial Additions and Acquisitions

(In millions of Canadian dollars)

	Twelve months ended December 31,	
	2007	2006
Growth capital expenditures	23.9	70.9
Maintenance capital expenditures	1.4	3.0
Total capital expenditures	25.3	73.9
Acquisitions of non-controlling interest	6.7	-
Total capital additions and acquisitions	32.0	73.9

In the fourth quarter of 2007, additions to property, plant and equipment including acquisitions amounted to $9.0 million, most of which was growth capital. Keyera incurred maintenance and repair expenses of $3.2 million that were included in operating costs during the fourth quarter of 2007. The growth capital expenditures included $2.0 million for the acquisition of an acid gas disposal well for the Brazeau River plant, $1.6 million for the expansion of the truck terminal at Fort Saskatchewan, $1.2 million for the acquisition of pipe and design work for the Caribou North Trutch Pipeline project, $0.7 million for work done on the construction of a fourth pipeline between our Fort Saskatchewan facility and Edmonton terminal, and $0.4 million related to the construction of new camp facilities at the Caribou plant and various other small projects.

Total capital additions and acquisitions amounted to $32.0 million in 2007, consisting of $1.4 million of maintenance capital, $23.9 million of growth capital and $6.7 million of acquisitions. In addition to maintenance capital expenditures, Keyera incurred maintenance and repair expenses of $28.0 million that were included in operating costs.

In 2007, Keyera invested in the following significant growth projects:

- $6.7 million related to the acquisition of additional ownership interests in Rimbey Pipeline Limited Partnership, bringing Keyera's ownership to 100%
- $4.4 million for new gathering pipelines in the Foothills Region
- $4.2 million at the Bigoray, Brazeau River and Nordegg River gas plants to upgrade systems and equipment and expand acid gas disposal capacity
- $2.6 million for upgrades and expansion of equipment at the Rimbey gas plant
- $2.2 million for the expansion of the truck terminal at Fort Saskatchewan
- $2.1 million for the acquisition of a site in northeast B.C. close to the Caribou North gathering system to enable future expansion
- $1.9 million related to modifications at the Rimbey gas plant to enable the tie-in of equipment required for the ethane extraction project

In 2008, Keyera anticipates investing between $80 million and $100 million on growth capital projects, but the actual level of growth capital investment is dependent upon a number of factors including available opportunities, timing of regulatory approvals and agreements with customers. The 2008 spending includes commitments and carry over from the unfinished 2007 capital program. Sufficient capacity is available in the current credit facilities to fund the 2008 expenditures.

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 $84 million. In addition to the working capital required for inventory, Keyera typically utilizes approximately $25 to $45 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 Western Canada Sedimentary Basin 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. (See "Marketing Risk Management" in this MD&A.)

For a further discussion of the risks identified in this MD&A, other risks and trends that could affect the 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 Keyera's Annual Information Form 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 2008 capital expenditures and distributions to be funded by cash flow from operations and borrowing on available debt facilities.

Debt covenants

Keyera has established credit facilities consisting of a $150 million committed unsecured revolving term facility that matures on April 21, 2010 and $30 million of unsecured revolving demand facilities. These 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. As of December 31, 2007 there were no drawings under these Credit Facilities.

The bank credit facilities contain a covenant that the Fund and its subsidiaries will not distribute in any twelve month period more than 105% of the distributable cash flow attributable to that twelve month period. For the year ended December 31, 2007, Keyera distributed 66% of its distributable cash flow, using the definitions in the bank credit facilities. Those facilities are also 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 the credit agreements provide for the deduction of net working capital items in the calculation of debt. The following are the ratios as calculated in accordance with the covenants as at December 31, 2007:

Covenant	Position as at December 31, 2007
Debt to EBITDA not to exceed 3.5	1.59
Debt to Capitalization not to exceed 0.55	0.26

Keyera has $335 million of long-term senior unsecured notes as follows: $20 million bearing interest at 5.42% and maturing in August 2008; $90 million bearing interest at 5.23% and maturing in October 2009; $52.5 million bearing interest at 5.79% and maturing in August 2010; $52.5 million bearing interest at 6.155% and maturing in August 2013; $60 million bearing interest at 5.89% and maturing in December 2017; and $60 million bearing interest at 6.14% and maturing in December 2022. These notes are subject to three major financial covenants: "Consolidated Debt to Consolidated EBITDA", "Consolidated EBITDA to Consolidated Interest Charges" and "Priority Debt to Consolidated Total Assets".

The calculations for each of these ratios are based on specified definitions. The following are the ratios calculated in accordance with the covenants as at December 31, 2007 for the notes maturing in 2008, 2009, 2010 and 2013:

Covenant	Position as at December 31, **2007**
Debt to EBITDA not to exceed 3.5	**2.14**
EBITDA to Interest Charges not less than 3.0	**10.90**
Priority Debt to Total Assets not to exceed 15%	**0%**

The following are the ratios calculated in accordance with the covenants as at December 31, 2007 for the notes maturing in 2017 and 2022:

Covenant	Position as at December 31, **2007**
Debt to EBITDA not to exceed 5.0	**1.42**
EBITDA to Interest Charges not less than 2.0	**8.35**
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. Management expects that upon maturity of the credit facilities, adequate replacement facilities will be established.

Regulatory risk

Keyera is subject to a range of laws and regulations imposed by various levels of government and regulatory bodies in the jurisdictions in which it operates. In 2007, regulatory changes in the areas of taxation and the environment have had the most direct impact on Keyera. (See "Business Environment").

While these laws and regulations affect all dimensions of Keyera's activities, Keyera does not believe that they affect its operations in a manner materially different from other comparable businesses operating in the same jurisdictions. A more complete discussion of regulatory risks can be found in the Annual Information Form available on SEDAR.

Credit risk

Credit risk is the risk of loss resulting from non-performance of contractual payment 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, 2007, the accounts receivable from Keyera's two largest customers accounted for less than 1% of accounts receivable (2006 – less than 1%).

With respect to counterparties for financial instruments used for economic hedging purposes, Keyera limits its credit risk by dealing with recognized futures exchanges or investment grade financial institutions and by maintaining credit policies that significantly reduce 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 variability 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 reduces 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 products 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 risks associated with these activities. 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 56% of 2007 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$240.1 million of sales were priced in U.S. dollars in 2007.

Commitments

Keyera has assumed various contractual obligations in the normal course of its operations. At December 31, 2007, the obligations that represent known future cash payments that are required under existing contractual arrangements are as follows:

		Payments Due by Period					
Contractual Obligations	**Total**	2008	2009	2010	2011	2012	After 2012
Long-term debt[1]	**335,000**	20,000	90,000	52,500	-	-	172,500
Operating leases[2]	**33,845**	8,749	7,926	6,359	4,964	3,915	1,932
Purchase obligations[3]	-	-	-	-	-	-	-
Total contractual obligations	**368,845**	28,749	97,926	58,859	4,964	3,915	174,432

[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 lease 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 eleven 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 market prices. The future volumes and prices for these contracts cannot be reasonably determined.*

Unitholder Distributions

Comparison of distributions paid to cash flow from operating activities and net earnings

The following table presents a comparison of distributions paid to net earnings and cash flow from operating activities:

(Thousands of Canadian dollars)	Three months ended December 31 **2007**	Twelve months ended December 31, **2007**	2006	2005
Cash flow from operating activities	**45,497**	**119,825**	110,656	62,147
Net earnings	**40,027**	**14,479**	68,078	60,680
Cash distributions paid	**22,952**	**89,799**	86,509	77,013
Excess (shortfall) of cash flow from operating activities over distributions paid	**22,545**	**30,026**	24,147	(14,866)
Excess (shortfall) of net earnings over distributions paid	**17,075**	**(75,320)**	(18,431)	(16,333)

In 2007, cash flow from operating activities was $119.8 million, $30.0 million greater than distributions paid. Included in the calculation of cash flow from operating activities was $25.5 million to fund an increase in non-cash working capital. In the fourth quarter of 2007, cash flow from operating activities was $45.5 million, including $3.9 million generated from a decrease in non-cash working capital. Cash flow from operating activities both in the fourth quarter of 2007 and for the year were sufficient to fund cash distributions paid.

Cash distributions paid for 2007 of $89.8 million exceeded net earnings by $75.3 million. The shortfall is attributable to the inclusion of non-cash items for future income taxes ($72.6 million), depreciation, amortization and accretion ($44.5 million) and unrealized losses on financial instruments ($12.6 million) in the calculation of net income. In the fourth quarter of 2007, net earnings of $40.0 million exceeded cash distributions by $17.0 million.

Future income taxes can fluctuate from period to period as a result of changes in tax laws and rates (such as the enactment in the second quarter of 2007 of the tax on distributions of flow-through entities or the reduction of income tax rates in 2006 and 2007) or changes in the operating results of the underlying operating entities of Keyera. These items do not affect cash flow generated in the current period.

Non-cash charges such as depreciation and amortization are based upon the historical cost of Keyera's property, plant and equipment and do not accurately represent the fair market value or the replacement cost of the assets in today's economic environment, nor do they affect cash flow generated in the current period.

Non-cash unrealized gains and losses on financial instruments result from Keyera's use of financial contracts, such as energy-related forward sales, price swaps, physical exchanges and options to manage some of the commodity price risk inherent in the marketing business. Their fair value is determined based upon estimates of future prices. The change in fair value of these contracts during the current period has no effect on cash flow generated. Upon settlement in future periods, the unrealized estimate is reversed and the realized gain or loss is included in earnings.

Due to the inclusion of such non-cash charges in net earnings, distributions paid may exceed net earnings. Although non-cash charges do not affect current period cash generation, any excess of distributions over net earnings would be a return of unitholders' capital.

Distributable Cash Flow

Distributable cash flow is not a standard measure under GAAP and therefore may not be comparable to similar measures reported by other entities. Distributable cash flow is used to assess the level of cash flow generated from ongoing operations and to evaluate the adequacy of internally generated cash flow to fund distributions.

Following is a reconciliation of distributable cash flow to its most closely related GAAP measure, cash flow from operating activities.

	Three months ended December 31		Twelve months ended December 31,	
(Thousands of Canadian dollars)	**2007**	2006[1]	**2007**	2006[1]
Cash flow from operating activities	**45,497**	42,130	**119,825**	110,656
Add (deduct):				
Changes in non cash working capital	**(3,885)**	(13,584)	**25,450**	(6,545)
Maintenance capital	**(192)**	(288)	**(1,437)**	(3,011)
Non-controlling interest distributable cash flow	**-**	(285)	**(369)**	(1,153)
Distributable cash flow	**41,420**	27,973	**143,469**	99,947
Distributions to unitholders	**22,965**	21,742	**90,206**	86,605

[1] *The calculation of distributable cash flow for the comparative period has been amended to consider the non-cash effect of unrealized foreign exchange gains and losses. For the three and twelve months ended December 31, 2006, $287 and $228 of unrealized foreign exchange gains have been included in the change in non-cash working capital.*

Distributable cash flow of $41.4 million in the fourth quarter of 2007 and $143.5 million for the year exceeded distributions to unitholders of $18.5 million and $53.3 million in the respective periods.

Changes in non-cash working capital are excluded from the determination of distributable cash flow because they are primarily the result of seasonal fluctuations in product inventories or other temporary changes and are generally funded with short-term debt. Also deducted from distributable cash flow are maintenance capital expenditures that are funded from current operating cash flow.

Distribution policy

In determining the level of cash distributions to unitholders, Keyera's Board of Directors takes into consideration current and expected future levels of distributable cash flow (including income tax), capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors.

Changes in non-cash working capital are primarily the result of seasonal fluctuations in product inventories or other temporary changes and are generally funded with short-term debt. These changes in non-cash working capital are therefore excluded in the determination of distributable cash flow.

Over the long-term, Keyera expects to pay distributions from distributable cash flow. Growth capital expenditures will be funded from retained operating cash flow, along with proceeds from additional debt or equity, as required. Although Keyera intends to continue to make regular monthly cash distributions to its unitholders, these distributions are not guaranteed.

Sustainability of productive capacity

Keyera's Gathering and Processing and NGL Infrastructure segments operate long-life infrastructure assets consisting of natural gas processing plants and gathering systems, NGL processing plants, storage facilities and transportation facilities. These facilities provide services to numerous energy producers over a wide geographic area. Throughput at each natural gas processing plant is dependent upon the natural gas production of third party producers within the capture area or franchise area of the plant. Demand for fractionation, storage and transportation services is dependent upon the supply of NGL mix obtained from the processing of third party raw natural gas and the market demand for end-use products (propane, butane and condensate).

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. These maintenance and repair expenditures totaled $3.4 million in the fourth quarter of 2007 and $29.5 million for the year. Of these amounts, $3.2 million and $28.0 million were included in operating costs and will be recovered through the fee structure over varying periods of time, depending upon the fee structure. At these levels of maintenance and repair, Keyera's plants and facilities can continue to operate safely for decades to come. Significant capital expenditures are not normally required to maintain the existing productive capacity, but may be required if significant changes are made in regulatory requirements.

Several of Keyera's sour gas plants rely on acid gas injection to dispose of the hydrogen sulphide and other 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 process is dependent upon the availability of suitable reservoirs. If suitable reservoirs were not available, alternate processes would be required, the capacity of the plant could be reduced or expenditures required to replace the lost capacity would be necessary. These alternatives would have an adverse effect on cash flow.

Cash flows from operating activities are determined primarily by the quantity and composition of product throughput at the facility and the fee structure. Throughput is influenced by the ongoing development activities of numerous third parties who may increase production volumes by drilling new wells, tying in previously drilled wells, completing new zones in existing wells or enhancing production volumes through stimulation or enhanced recovery techniques. If third parties are unsuccessful in their development activities, Keyera's cash flow could be adversely affected despite having physical capacity available. Growth capital expenditures are generally undertaken to expand capture areas, add new capacity or introduce new services. If Keyera is unsuccessful in extending capture areas or adding new capacity and services, cash flow from operating activities may be reduced.

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

Additional information on the capacities and constraints related to Keyera's plants, other risks and trends that could affect the financial performance of Keyera and the steps taken 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.

Units and Convertible Debentures

During 2007, $1.7 million of convertible debentures (before adjustment for deferred financing costs) were converted into 143,321 trust units and 190,298 trust units were issued under the DRIP in consideration of $3.3 million, bringing the total units outstanding at December 31, 2007 to 61,264,372. Convertible debentures outstanding at December 31, 2007 were $21.8 million.

Fund Reorganization

In June 2007, Unitholders approved an internal reorganization of Keyera's legal structure (the "Reorganization"). Due to interpretation issues surrounding the SIFT Legislation, Keyera amended certain elements of the Reorganization prior to implementation. On January 2, 2008, upon receipt of a favourable advance ruling from the Canada Revenue Agency and the final order from the Alberta Court of Queen's Bench approving the plan of arrangement for the amended Reorganization, the Reorganization was completed. The Reorganization is described in detail in the Material Change Report as filed on SEDAR at **www.sedar.com** on January 11, 2008.

The Reorganization streamlined Keyera's legal structure and simplified accounting, legal reporting and income tax compliance, all of which is expected to reduce the general and administrative costs associated with these activities. As a result of the amendments to the Reorganization, there were not any significant immediate tax savings within Keyera's structure, but the new structure does permit Keyera to defer the utilization of some tax pools until after January 1, 2011. This enhanced tax planning flexibility should enable Keyera to minimize the amount of cash taxes payable in 2011, when Keyera is expected to become taxable under the SIFT Legislation.

Keyera is looking at a variety of options to continue to enhance it tax planning flexibility, including the possibility of undertaking a further restructuring depending on whether amendments are made to the SIFT Legislation. (See "Business Environment – New Tax on Flow-through Entities"). As well, Keyera plans to reduce the use of its available tax deductions from 2008 through 2010, thereby increasing deductions available for the years after 2010.

Accounting Matters and Controls

Changes in Accounting Policies

On January 1, 2007, we adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook Sections:

- Section 1530, Comprehensive Income;
- Section 3251, Equity;
- Section 3855, Financial Instruments – Recognition and Measurement;
- Section 3861, Financial Instruments – Presentation and Disclosure; and
- Section 3865, Hedges.

For a description of the new accounting policies and the impact on the Fund's financial statements including the impact on the Fund's deferred financing fees, long-term debt and opening accumulated deficit refer to note 2 of the Consolidated Financial Statements for the year ended December 31, 2007.

Future Accounting and Reporting Changes

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in the convergence of Canadian GAAP, as used by public companies, with International Financial Reporting Standards over a transitional period. The AcSB has developed and published a detailed implementation plan, with a changeover date for fiscal years beginning on or after January 1, 2011. This initiative is in its early stages as of the date on these annual Consolidated Financial Statements. Accordingly, it would be premature to assess the impact of the initiative on the Fund at this time.

Financial Instruments – Disclosures and Presentation

The AcSB has issued CICA Handbook Sections 3862 and 3863, Financial Instruments – Disclosures, and Financial Instruments – Presentation. Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These standards will be effective for the Fund for periods ending after January 1, 2008.

Capital Disclosures

The AcSB has issued CICA Handbook Section 1535, Capital Disclosures, which requires entities to disclose their objectives, policies and processes for managing capital and whether they are in compliance with any externally imposed capital requirements. This standard will be effective for the Fund for periods ending after January 1, 2008.

Inventories

The AcSB has issued CICA Handbook Section 3031, Inventories, which essentially modifies guidance relating to the scope, measurement and allocation of costs for inventory. The Fund is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. This standard will be effective for the Fund for periods ending after January 1, 2008.

Goodwill and Intangible Assets

In February 2008, the AcSB issued CICA Handbook Section 3064, Goodwill and Intangible Assets, replacing existing guidance (Sections 3062 and 3450) for these areas. This new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Fund is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. This standard will be effective for the Fund for periods ending after January 1, 2009.

Control Environment

Disclosure Controls and Procedures

As of December 31, 2007, 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, 2007, 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, 2007, there have been no material changes in internal control over financial reporting.

Selected Financial Information

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

(Thousands of Canadian dollars, except per unit information)	2005	2006	**2007**
Operating revenues			
Marketing	1,013,334	1,161,899	**1,250,541**
Gathering and Processing	139,274	166,736	**187,490**
NGL Infrastructure	34,959	39,888	**41,110**
Net earnings	60,680	68,078	**14,479**
Net earnings per unit *($/unit)*			
Basic	1.03	1.12	**0.24**
Diluted	0.96	1.10	**0.24**
Distributions to unitholders	78,541	86,605	**90,206**
Distributions to unitholders per unit *($/unit)*	1.33	1.43	**1.48**
Trust Units outstanding *(thousands)*			
Weighted average *(basic)*	58,947	60,604	**61,098**
Weighted average *(diluted)*	63,075	62,794	**61,098**
Total assets	1,218,160	1,223,012	**1,330,999**
Total long-term financial liabilities	345,955	338,499	**517,740**

2007 compared to 2006

For 2007 revenues from Marketing were $1,250.5 million, an increase of $88.6 million compared to the previous year. Higher prices, partially offset by lower volumes, and the growing contribution from the crude oil midstream business accounted for the increase. Also included in 2007 revenues were $20.0 million of charges related to the settlement and change in fair value of financial contracts that were part of Keyera's risk management program.

Revenues from facilities were $228.6 million, up $22.0 million compared to 2006.

Gathering and Processing revenue for 2007 was $187.5 million, an increase of $20.8 million, or 12%, compared to the previous year. The increase was due primarily to higher throughput in the Foothills Region, the flow through of turnaround costs incurred at the Rimbey, Brazeau River and Bigoray gas plants, the conversion of fixed fee arrangements to flow-through arrangements and incremental fees from the new compression added at the Rimbey gas plant in late 2006 and early 2007.

NGL Infrastructure revenue for 2007 was $41.1 million, an increase of $1.2 million, or 3%, compared to the previous year. The increase is primarily due to higher storage revenues at Keyera's Fort Saskatchewan facility.

Consolidated net earnings for 2007 were $14.5 million, a decrease of $53.6 million from 2006. The decrease was due primarily to the non-cash future income tax expense, higher general and administrative costs, interest expense and depreciation charges, partially offset by strong operating margins in all segments.

The Fund declared $90.2 million of distributions to unitholders in 2007, an increase of $3.6 million due to an increase in the distributions paid per unit in May 2007, as well as a greater number of units outstanding resulting from conversions of debentures and the DRIP.

2006 compared to 2005

For 2006, revenues from Marketing were $1,161.9 million, an increase of $148.6 million compared 2005. 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 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 margins.

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

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

Three months ended *(Thousands of Canadian dollars)*	**March 31 2007**	**June 30 2007**	**September 30 2007**	**December 31 2007**
Operating revenues				
Marketing	307,342	292,326	276,957	373,916
Gathering and Processing	41,949	44,277	50,744	50,520
NGL Infrastructure	9,692	9,525	10,044	11,849
Net earnings[1]	19,012	(59,870)	15,310	40,027
Net earnings per unit *($/unit)*				
Basic	0.31	(0.98)	0.25	0.65
Diluted	0.31	(0.95)	0.25	0.64
Trust units outstanding *(thousands)*				
Weighted average *(basic)*	60,972	61,061	61,136	61,219
Weighted average *(diluted)*	62,918	62,967	63,011	63,059
Distributions to unitholders	21,773	22,538	22,931	22,965

Three months ended *(Thousands of Canadian dollars)*	March 31 2006	June 30 2006	September 30 2006	December 31 2006
Operating revenues				
Marketing	316,841	279,241	279,492	286,325
Gathering and Processing	38,053	40,772	44,290	43,621
NGL Infrastructure	9,606	8,549	10,878	10,855
Net earnings[1]	15,384	25,969	11,797	14,928
Net earnings per unit *($/unit)*				
Basic	0.26	0.43	0.19	0.25
Diluted	0.22	0.39	0.16	0.24
Trust units outstanding *(thousands)*				
Weighted average *(basic)*	60,291	60,560	60,692	60,865
Weighted average *(diluted)*	63,321	62,768	62,817	62,869
Distributions to unitholders	21,553	21,631	21,679	21,742

[1] *Since the adoption of the new accounting standards effective January 1, 2007, Keyera has had no transactions that required the use of other comprehensive income and therefore comprehensive income equals net earnings.*

December 31, 2007 compared to September 30, 2007

Marketing revenues of $373.9 million in the fourth quarter of 2007 increased from the third quarter of 2007 by $96.9 million. This increase was due to the seasonal increase in sales volumes and higher prices.

Net earnings were $40.0 million, an increase of $24.7 million due primarily to the strong operating margins earned in the Marketing segment and the recognition of a $11.7 million future income tax recovery.

September 30, 2007 compared to June 30, 2007

Third quarter Marketing revenues of $277.0 million decreased from the prior quarter by $15.4 million. This decrease was due to a combination of lower NGL volumes, particularly in butane and condensate, and the effect of the $5.7 million of unrealized loss on financial instruments.

Gathering and Processing revenue of $50.7 million increased by $6.5 million due to higher throughput at most plants and higher fees at the Bigoray and Brazeau River gas plants. Furthermore, volumes at the Rimbey gas plant improved over the previous quarter as it was taken offline for a 17-day turnaround in the second quarter.

Net earnings were $15.3 million, an increase of $75.2 million from previous quarter. This increase was primarily due to the recording of $80.2 million of future income taxes in the second quarter as a result of the Canadian government enacting taxation on publicly traded income trusts. Without the effect of this non-cash future income tax expense, net earnings for the third quarter decreased by $5.1 million from the second quarter, largely due to lower Marketing operating margins.

June 30, 2007 compared to March 31, 2007

For the second quarter of 2007, Marketing revenues of $292.3 million decreased by $15.0 million from the prior quarter. This decrease in revenues was due primarily to a seasonal decline in sales volumes.

Gathering and Processing revenue of $44.3 million increased by $2.3 million primarily due to higher throughput volumes in the Foothills Region, despite maintenance turnarounds at the Rimbey gas plant, Keyera's largest facility, and the Brazeau North gas plant.

NGL Infrastructure revenue of $9.5 million remained relatively unchanged from the first quarter of 2007, reflecting the long-term storage contracts established in early 2007.

A net loss of $59.9 million was recorded, a decrease of $78.9 million from the prior quarter. This loss was due to the recording of an $80.2 million provision for future income tax expense resulting from the enactment of the Canadian government's tax on publicly traded income trusts starting in 2011.

March 31, 2007 compared to December 31, 2006

Marketing revenues of $307.3 million increased by $21.0 million due to strong seasonal demand for propane over the last quarter of 2006. First quarter butane margins and demand continued to improve over the previous quarter, along with the market conditions for condensate. Keyera's crude oil midstream also contributed to the increase in Marketing revenue.

Gathering and Processing revenue for the first quarter of 2007 was $41.9 million, a decrease of $1.7 million from the last quarter of 2006. The decrease in revenue was due to a slight decrease in throughput volume in the West Central Region offset by higher volumes in the Foothills Region.

Operating revenues from NGL Infrastructure were $9.7 million, a decrease of $1.2 million from the fourth quarter of 2006. This decrease was primarily due to lower fractionation revenues, particularly at the Fort Saskatchewan facility.

Net earnings were $19.0 million, an increase of $4.1 million from the previous quarter. This increase was primarily due to stronger marketing operating margins offset by higher general and administrative costs.

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.

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

Gathering and Processing revenue of $44.3 million increased by $3.5 million due to higher throughput, 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 the 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 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.

Management's Report

Keyera management is responsible for the preparation of the accompanying consolidated financial statements, which have been prepared by management in accordance with Canadian generally accepted accounting principles and include amounts 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 report operating and financial results realistically and that Keyera's assets are safeguarded.

Deloitte & Touche LLP, independent external auditors, appointed by the Board of Directors, have completed their audit and submitted their report. 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 Officer

David G. Smith
Executive Vice President and Chief Financial Officer

February 22, 2008

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, 2007 and 2006 and the consolidated statements of net earnings, comprehensive income, accumulated deficit 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, 2007 and 2006 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, 2008

Consolidated Statements of Financial Position

As at December 31 *(Thousands of Canadian dollars)*	**2007** **$**	2006 $
Assets		
Current assets		
Cash	15,657	-
Accounts receivable	243,889	160,112
Inventory	76,594	53,939
Asset held for sale *(note 7)*	-	4,200
Other current assets	2,299	4,327
	338,439	222,578
Property, plant and equipment *(note 3)*	914,087	924,947
Intangible assets *(note 4)*	6,394	10,553
Goodwill *(note 4)*	71,234	64,934
Future income tax assets *(note 9)*	845	-
	1,330,999	1,223,012
Liabilities and Unitholders' Equity		
Current liabilities		
Bank indebtedness	-	96
Accounts payable and accrued liabilities	235,124	148,318
Distributions payable *(note 12)*	7,658	7,251
Credit facilities *(note 5)*	-	107,984
Current portion of long-term debt *(note 5)*	20,000	-
	262,782	263,649
Long-term debt *(note 5)*	313,243	215,000
Convertible debentures *(note 6)*	21,476	23,542
Asset retirement obligation *(note 8)*	37,807	34,533
Future income tax liabilities *(note 9)*	145,214	65,424
	780,522	602,148
Non-controlling interest *(note 18)*	-	2,744
Unitholders' equity		
Unitholders' capital *(note 10)*	681,925	677,025
Deficit	(131,448)	(58,905)
	550,477	618,120
	1,330,999	1,223,012

See accompanying notes to the consolidated financial statements

Commitments and contingencies *(note 15)*
Subsequent event *(note 19)*

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

Wesley R. Twiss
Director

James V. Bertram
Director

Consolidated Statements of Net Earnings, Comprehensive Income and Deficit

For the Years Ended December 31 *(Thousands of Canadian dollars, except unit information)*	**2007** **$**	2006 $
Operating revenues		
Marketing	1,250,541	1,161,899
Gathering and Processing	187,490	166,736
NGL Infrastructure	41,110	39,888
	1,479,141	1,368,523
Operating expenses		
Marketing	1,172,010	1,102,045
Gathering and Processing	103,792	96,558
NGL Infrastructure	24,253	23,956
	1,300,055	1,222,559
	179,086	145,964
General and administrative	21,882	18,892
Interest expense on long-term indebtedness	16,077	13,838
Other interest expense	4,099	4,318
Depreciation and amortization	42,040	39,843
Accretion expense *(note 8)*	2,482	2,257
Impairment expense	728	373
	87,308	79,521
Earnings before income tax and non-controlling interest	91,778	66,443
Income tax expense (recovery) *(note 9)*	76,993	(2,660)
Earnings before non-controlling interest	14,785	69,103
Non-controlling interest	306	1,025
Net earnings	14,479	68,078
Other comprehensive income	-	-
Comprehensive income *(note 2)*	14,479	68,078
Deficit, beginning of year	(58,905)	(40,378)
Change in accounting policies *(note 2)*	3,184	-
Distributions to unitholders *(note 12)*	(90,206)	(86,605)
Deficit, end of year	(131,448)	(58,905)
Weighted average number of units *(thousands) (note 11)*		
– basic	61,098	60,604
– diluted	61,098	62,794
Net earnings per unit *(note 11)*		
– basic	0.24	1.12
– diluted	0.24	1.10

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

For the Years Ended December 31 *(Thousands of Canadian dollars)*	**2007** **$**	2006 $
Net inflow (outflow) of cash:		
Operating activities		
Net earnings	14,479	68,078
Items not affecting cash:		
Depreciation and amortization	42,040	39,843
Accretion expense	2,482	2,257
Impairment expense	728	373
Unrealized loss (gain) on financial instruments	12,563	(263)
Loss on sale of assets	245	-
Future income tax expense (recovery) *(note 9)*	72,645	(7,042)
Non-controlling interest	306	1,025
Asset retirement obligation expenditures *(note 8)*	(213)	(160)
Changes in non-cash operating working capital *(note 16)*	(25,450)	6,545
	119,825	110,656
Investing activities		
Capital expenditures	(25,313)	(73,868)
Acquisition of non-controlling interest *(note 18)*	(6,716)	-
Proceeds on sale of assets	4,704	-
Additions to intangibles	-	(1,115)
Changes in non-cash working capital *(note 16)*	(1,114)	(651)
	(28,439)	(75,634)
Financing activities		
(Repayment) issuance of debt under credit facilities *(note 5)*	(107,984)	41,984
Issuance of long-term debt, net of financing costs *(note 5)*	118,895	-
Issuance of trust units *(note 10)*	3,255	4,252
Distributions paid to unitholders *(note 12)*	(89,799)	(86,509)
Distributions or dividends paid to others	-	(479)
	(75,633)	(40,752)
Net cash inflow (outflow)	15,753	(5,730)
(Bank indebtedness) cash, beginning of year	(96)	5,634
Cash (bank indebtedness), end of year	15,657	(96)

See accompanying notes to the consolidated financial statements

See note 16 for cash interest and taxes paid

Notes to Consolidated Financial Statements

For the Years Ended December 31, 2007 and 2006
(All amounts expressed in thousands of Canadian dollars, except as 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 subsidiaries include Keyera Energy Facilities Ltd. ("KEFL"), Keyera Energy Ltd. ("KEL"), Keyera Energy Inc. ("KEI"), and Rimbey Pipeline Limited Partnership ("RPLP").

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 is 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 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.

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars 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 from marketing NGLs and natural gas and from crude oil midstream activities is recognized based on volumes delivered to customers at contracted delivery points and rates and when collection is reasonably assured.

Gathering and Processing revenue

Gathering and Processing revenue is generated 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 is recognized when services have been performed and collection is reasonably assured. 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 and collection is reasonably assured.

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.

Cash and cash equivalents

Cash may include cash equivalents such as short-term investments with maturities 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 five to thirty-two years for Gathering and Processing, twelve to thirty-one years for NGL Infrastructure, two to twenty-four years for Marketing and six to twenty-two years for corporate assets.

Impairment on property, plant and equipment is measured in a two-step process. Step one calculates the net recoverable amount, 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. Fair value is determined by discounting future estimated cash flows.

Intangible assets

Goodwill

Goodwill resulted from business combinations and represents the portion of the purchase price that was in excess of the fair value of net identifiable assets acquired. Goodwill is recorded at cost and is not subject to amortization. It is tested at least annually for impairment. The impairment test for goodwill is a two-step process. Step one consists of a comparison of the fair value of a reporting unit with its carrying amount, including the goodwill allocated to the reporting unit. Measurement of the fair value of a reporting unit is based on one or more fair value measures, including present value calculations of estimated future cash flows and estimated amounts at which the unit as a whole could be bought or sold in a current transaction between willing parties. The Fund also considers its market capitalization as of the date of the impairment test. If the carrying amount of the reporting unit exceeds its fair value, step two requires the fair value of the reporting unit to be allocated to the underlying assets and liabilities of that reporting unit, resulting in an implied fair value of goodwill. If the carrying amount of the reporting unit exceeds the implied fair value of that goodwill, an impairment loss equal to the excess is recorded in net earnings.

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.

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 net 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 net 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 Canadian Income Tax Act, the Fund is considered to be a "mutual fund trust" and, until December 31, 2010, 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 13. The LTIP is a stock appreciation right as defined by the Canadian Institute of Chartered Accountants. The amount recognized in compensation expense is determined by multiplying the number of units deemed to have been earned by the current market price of the units. 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 are 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 "if-converted" 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.

Certain of the comparative figures in prior periods have been reclassified to conform to the presentation in the current period.

Changes in accounting policies

Financial instruments

On January 1, 2007, the Fund adopted the following accounting standards issued by the Canadian Institute of Chartered Accountants ("CICA"):

- Section 1506, Accounting Changes;
- Section 1530, Comprehensive Income;
- Section 3251, Equity;
- Section 3855, Financial Instruments – Recognition and Measurement;
- Section 3861, Financial Instruments – Disclosure and Presentation; and
- Section 3865, Hedges

The Fund has adopted these standards in accordance with their transition provisions and comparative consolidated financial statements have not been restated. The Fund has selected January 1, 2004 as the date for identification of embedded derivatives. Transition amounts have been recorded in opening deficit.

All financial instruments must initially be recognized at fair value on the balance sheet. Subsequent measurement of the financial instruments is based on their classification. The Fund has classified each financial instrument into one of the following categories:

- Financial assets and financial liabilities held for trading
- Loans or receivables
- Financial assets held to maturity
- Financial assets available for sale
- Other financial liabilities

The classification depends on the characteristics and the purpose for which the financial instruments were acquired. Except in very limited circumstances, the classification of financial instruments is not changed subsequent to initial recognition.

Held for trading

Financial assets and financial liabilities classified as held for trading are measured at fair value and changes in those fair values are recognized in net earnings. Derivative instruments and cash have been classified as held for trading. Gains and losses related to derivative contracts are recognized in revenue in the period in which they arise. The estimated fair value of assets and liabilities held for trading is determined by reference to quoted market prices and, if not available, to estimates from third-party brokers or dealers. Transaction costs related to financial assets and financial liabilities classified as held for trading are charged to earnings as incurred.

Available for sale

Financial assets available for sale are measured at fair value, with changes in those fair values recognized in other comprehensive income. Currently, the Fund does not have any financial assets classified as available for sale. Transaction costs related to financial assets classified as available for sale would be charged to earnings as they occur.

Held to maturity

Financial assets held to maturity are measured at amortized cost using the effective interest rate method of amortization. Currently, the Fund does not have any financial assets classified as held to maturity. Transaction costs related to financial assets held to maturity would be charged to earnings as they occur.

Loans or receivables

Loans or receivables are measured at amortized cost using the effective interest rate method of amortization. Trade accounts receivables have been classified in this category. The related transaction costs would be charged to earnings as they arise.

Other financial liabilities

Other financial liabilities include accounts payable, accrued liabilities, distributions payable, short-term debt, convertible debentures and long-term debt. With the exception of derivative instruments, the Fund has classified all financial liabilities as other financial liabilities. Transaction costs relating to short-term liabilities are charged to earnings as they occur. For long-term liabilities, the transaction costs that are directly attributable to the issuance of a financial liability are included with the fair value initially recognized for that financial instrument. These costs are amortized to earnings using the effective interest rate method.

As of January 1, 2007, unamortized deferred financing fees of $985 relating to the Fund's long-term debt and $502 relating to convertible debentures have been reclassified for presentation purposes from intangible assets to long-term debt and convertible debentures. These fees are now amortized to earnings using the effective interest rate method.

The Fund assesses at each balance sheet date whether a financial asset carried at cost is impaired. If there is objective evidence that an impairment loss exists, the amount of the loss is measured as the difference between the carrying amount of the asset and its fair value. The carrying amount of the asset is reduced and the amount of the loss is recognized in earnings.

Derivatives and embedded derivatives

Derivative financial instruments are financial contracts that derive their value from underlying changes in interest rates, foreign exchange rates, credit spreads, commodity prices, equities or other financial measures. The Fund uses financial instruments such as commodity price swaps, electricity price swaps, foreign exchange forward contracts, and interest rate swaps to manage its risks.

Natural gas, NGL and crude oil contracts that require physical delivery at fixed prices and do not meet the Fund's expected purchase, sale or usage requirements are accounted for as derivative financial instruments.

Derivatives may include those derivatives that are embedded in financial or non-financial contracts that are not closely related to the host contracts. With the adoption of the new accounting standards on financial instruments, such embedded derivatives are now to be accounted for separately from the host contract.

Derivative instruments, including embedded derivatives, are classified as held for trading and are recorded on the consolidated statements of financial position at fair value. Changes in the fair value of these financial instruments are recognized in earnings in the period in which they arise.

Hedge accounting

Effective January 1, 2007 the Fund has opted to discontinue the use of hedge accounting. All derivative instruments that previously qualified for hedge accounting have been recognized at fair value and unrealized gains and losses have been recorded in earnings.

Adopting these standards on January 1, 2007 resulted in the recognition of an asset held for trading in the amount of $3,314, a liability held for trading in the amount of $130 and a $3,184 reduction to the opening deficit. Assets held for trading are included in accounts receivable and liabilities held for trading are included in accounts payable and accrued liabilities. The effect on basic and diluted net earnings per unit was $0.05.

Comprehensive income

Comprehensive income consists of net earnings and other comprehensive income ("OCI"). OCI comprises the changes in the fair value of the effective portion of derivatives used as hedging items in a cash flow hedge, changes in the fair value of any available for sale financial instruments and foreign currency translation adjustments of self-sustaining foreign operations. Accumulated other comprehensive income ("AOCI") is a new equity category comprised of the cumulative amounts of OCI.

No amounts have been recorded in OCI or AOCI as a result of adopting this accounting standard.

Future Accounting and Reporting Changes

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board (AcSB) ratified a strategic plan that will result in the convergence of Canadian GAAP, as used by public companies, with International Financial Reporting Standards over a transitional period. The AcSB has developed and published a detailed implementation plan, with a changeover date for fiscal years beginning on or after January 1, 2011. This initiative is in its early stages as of the date on these annual Consolidated Financial Statements. Accordingly, it would be premature to assess the impact of the initiative on the Fund at this time.

Financial Instruments – Disclosures and Presentation

The AcSB has issued CICA Handbook Sections 3862 and 3863, Financial Instruments – Disclosures, and Financial Instruments – Presentation. Section 3862 requires entities to provide disclosures in their financial statements that enable users to evaluate the significance of financial instruments to the entitity's financial position and performance. It also requires that entities disclose the nature and extent of risks arising from financial instruments and how the entity manages those risks. Section 3863 establishes standards for presentation of financial instruments and non-financial derivatives and deals with the classification of financial instruments, from the perspective of the issuer, between liabilities and equity, the classification of related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These standards will be effective for the Fund for periods ending after January 1, 2008.

Capital Disclosures

The AcSB has issued CICA Handbook Section 1535, Capital Disclosures, which requires entities to disclose their objectives, policies and processes for managing capital and whether they are in compliance with any externally imposed capital requirements. This standard will be effective for the Fund for periods ending after January 1, 2008.

Inventories

The AcSB has issued CICA Handbook Section 3031, Inventories, which essentially modifies guidance relating to the scope, measurement and allocation of costs for inventory. The Fund is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. This standard will be effective for the Fund for periods ending after January 1, 2008.

Goodwill and Intangible Assets

In February 2008, the AcSB issued CICA Handbook Section 3064, Goodwill and Intangible Assets, replacing existing guidance (Sections 3062 and 3450) for these areas. This new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets subsequent to its initial recognition. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Fund is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. This standard will be effective for the Fund for periods ending after January 1, 2009.

3. Property, plant and equipment

As at December 31, 2007	**Cost** **$**	**Accumulated Depreciation** **$**	**Net Book Value** **$**
Gathering and Processing	841,671	(166,455)	675,216
NGL Infrastructure	276,807	(53,087)	223,720
Marketing	12,761	(771)	11,990
Corporate	9,311	(6,150)	3,161
Total	1,140,550	(226,463)	914,087

As at December 31, 2006	Cost $	Accumulated Depreciation $	Net Book Value $
Gathering and Processing	826,591	(141,875)	684,716
NGL Infrastructure	264,658	(39,843)	224,815
Marketing	12,179	(254)	11,925
Corporate	8,616	(5,125)	3,491
Total	1,112,044	(187,097)	924,947

Costs associated with assets under development, excluded from costs subject to depreciation, totaled $7,461 as at December 31, 2007 (2006 – $1,757).

During the year, a non-core gas plant was written down to its net realizable value, recognizing a $728 impairment expense.

4. Intangible assets and goodwill

As at December 31, 2007	Cost $	Accumulated Amortization $	Net Book Value $
Gathering and Processing *(a)*	39,219	-	39,219
NGL Infrastructure *(a)*	32,015	-	32,015
Marketing *(b)*	19,290	(12,896)	6,394
Total	90,524	(12,896)	77,628

As at December 31, 2006	Cost $	Accumulated Amortization $	Net Book Value $
Gathering and Processing *(a)*	39,219	-	39,219
NGL Infrastructure *(a)*	25,715	-	25,715
Marketing *(b)*	19,290	(10,223)	9,067
Corporate *(c)*	3,333	(1,847)	1,486
Total	87,557	(12,070)	75,487

(a) Intangible assets for the Gathering and Processing and NGL Infrastructure segments consist of goodwill.

(b) Intangible assets for the Marketing segment 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 one to six years. Amortization expense for the year ended December 31, 2007 was $2,673 (2006 – $1,930).

(c) For 2006, intangible assets for the corporate segment related to deferred financing fees. Upon adoption of the new accounting standards on financial instruments (note 2), deferred financing fees were reclassified to their related debt balances and amortized using the effective interest rate method over the remaining terms of the related debt. Long-term debt deferred financing fees are discussed further in note 5. Convertible debenture deferred financing fees are discussed further in note 6.

5. Credit facilities and long-term debt

As at	2007 $	2006 $
Bank credit facilities *(a)*	-	100,984
Revolving demand loan *(a)*	-	7,000
Total credit facilities	-	107,984
Current portion of long-term debt *(b)*	20,000	-
Long-term debt *(b)*	315,000	215,000
Deferred financing costs [1]	(1,757)	-
Total long-term debt	333,243	215,000

[1] *Deferred financing costs have been reclassified to long-term debt upon adoption of the new accounting standards (see note 2). Previously, these costs were included in intangible assets.*

(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, 2010, 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 rates for the year ended December 31, 2007 was 5.74% (2006 – 5.43%). As at December 31, 2007, the balance outstanding on the bank credit facilities was $nil (2006 – $107,984).

On July 12, 2007, the $7,000 unsecured revolving demand loan facility related to a subsidiary of the Partnership was terminated.

(b) In 2003, $125,000 of unsecured senior notes were issued by the Partnership and KEFL in three parts: $20,000 due in 2008 bearing interest at 5.42%, $52,500 due in 2010 bearing interest at 5.79% and $52,500 due in 2013 bearing interest at 6.16%. Interest is payable monthly. Financing costs of $1,215 have been deferred and are amortized using the effective interest rate method over the remaining terms of the related debt. The effective interest rates for the year ended December 31, 2007 were 5.63%, 5.95% and 6.29% for the notes due in 2008, 2010 and 2013 respectively (5.42%, 5.79% and 6.16% for the year ended December 31, 2006).

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 using the effective interest rate method over the remaining term of the debt. The effective interest rate for the year ended December 31, 2007 was 5.37% (2006 – 5.23%).

On September 4, 2007, $80,000 of unsecured senior notes were issued by KEFL and guaranteed by the Partnership and the Fund in two tranches: $40,000 due in 2017 bearing interest at 5.89% and $40,000 due in 2022 bearing interest at 6.14%. On December 2, 2007, a further $40,000 of unsecured senior notes were issued by KEFL in two tranches: $20,000 due in 2017 bearing interest at 5.89% and $20,000 due in 2022 bearing interest at 6.14%. Interest is payable semi-annually. Financing costs of $1,104 have been deferred and are amortized using the effective interest rate method over the terms of the related debt. The effective interest rates for the period were 5.94% and 6.18% for the notes due in 2017 and 2022 respectively.

6. Convertible debentures

In 2004, the Fund issued convertible unsecured subordinated debentures in the principal amount of $100,000. 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 $1,613 has been accrued for the twelve months ended December 31, 2007 (2006 – $1,776). 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, 2007, $78,178 debentures had been converted to trust units (2006 – $76,458).

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 using the effective interest rate method. Upon conversion of the debentures, the financing cost related to the principal amount of debt converted is adjusted and is recognized as a charge to unitholders' equity. As a result of conversions to date at December 31, 2007, $2,857 has been reclassified to unitholders' equity (2006 – $2,782). As at December 31, 2007, $346 of deferred financing costs remain. The effective interest rate for the year ended December 31, 2007 was 7.36% (2006 – 6.75%).

7. Asset held for sale

Asset held for sale consisted of an interest in an electrical generator. 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 proceeds of $4,200.

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	2007 $	2006 $
Asset retirement obligation, beginning of year	34,533	27,776
Liabilities acquired	644	151
Liabilities settled	(213)	(160)
Revisions in estimated cash flows	361	4,509
Accretion expense	2,482	2,257
Asset retirement obligation, end of year	37,807	34,533

The total undiscounted amount of cash flows required to settle the asset retirement obligations is $183,042 which has been discounted using a credit-adjusted risk-free rate of 7% (2006 – $183,159). 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

On June 22, 2007, Bill C-52 Budget Implementation Act, 2007 was enacted by the Canadian federal government. This legislation proposes to tax publicly traded trusts in Canada. The new tax is not expected to apply to the Fund until 2011 as the government has provided a transition period for publicly traded trusts that existed prior to November 1, 2006. As a result of the new tax legislation, the Fund recorded an additional $80.2 million future income tax expense and increased its future income tax liability in the second quarter of 2007. This adjustment represents taxable temporary differences of the Partnership that were previously not recorded for future income tax purposes. These temporary differences were originally recorded at a tax-effected rate of 31.5%.

During the fourth quarter of 2007, the federal government substantively enacted a 3.5% reduction to its federal corporate income tax rates. Accordingly, the Fund has recorded the temporary differences applicable to the Fund at a rate of 28% resulting in a $5.6 million reduction to the original future income tax expense of $80.2 million recorded in the second quarter of 2007.

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

	2007 **$**	2006 $
Earnings before tax and non-controlling interest	91,778	66,443
Income from the Fund distributable to unitholders	(8,652)	(36,061)
Income before taxes – operating subsidiaries	83,126	30,382
Income tax at statutory rate of 32.12% (2006 – 34.49%)	26,700	10,479
Impact of recording temporary differences of the Partnership	71,305	-
Non deductible items excluded from income for tax purposes	4,104	(142)
Rate adjustments and changes in estimates	(21,281)	(10,356)
Benefit of long-term incentive plan previously not recorded	-	(2,202)
Benefit of non-capital losses previously not recorded	(786)	(46)
Resource allowance	-	3
Adjustments to tax pool balances	(3,239)	(198)
Other	190	(198)
	76,993	(2,660)
Classified as:		
Current	4,348	4,382
Future	72,645	(7,042)
Income tax expense (recovery)	76,993	(2,660)

For income tax purposes, the Fund and its subsidiaries have non-capital losses carried forward of approximately $2,981 at December 31, 2007 ($11,987 at December 31, 2006) 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, 2007.

During the second quarter of 2007, the Fund recorded a $5,780 future income tax liability with a corresponding increase to goodwill. This adjustment relates to a prior period acquisition that did not reflect a future income tax impact for a temporary difference. A further $520 future tax liability and increase to goodwill was recorded relating to the acquisition of the minority interest in RPLP (see note 18).

The future income tax (liabilities) assets relate to losses and to the (taxable) deductible temporary differences in the carrying values and tax bases as follows:

	2007 **$**	2006 $
Property, plant and equipment	(152,747)	(71,611)
Asset retirement obligation	9,992	4,308
Long-term incentive plan	1,954	1,513
Non-capital losses	(38)	3,475
Intangible assets	(941)	(616)
Other	(3,434)	(2,493)
Future income tax liabilities	(145,214)	(65,424)
Property, plant and equipment	(444)	-
Asset retirement obligation	78	-
Non-capital losses	832	-
Intangible assets	379	-
Future income tax assets	845	-

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 will 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 trust 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 if there was trading 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.

The Fund has 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, 2006	**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**
Units issued on conversion of convertible debentures	143,321	1,645
Units issued pursuant to DRIP	190,298	3,255
Balance, December 31, 2007	**61,264,372**	**681,925**

11. Net earnings per unit

Basic per unit calculations for the years ended December 31, 2007 and 2006 were based on the weighted average number of units outstanding for the related period. Convertible debentures were in the money for the years ended December 31, 2007 and 2006 and contributed to the increase in diluted weighted average number of units for these periods.

	2007 **$**	2006 $
Net earnings – basic	14,479	68,078
Effect of convertible debentures (net of tax)[1]	-	1,161
Net earnings – diluted	14,479	69,239

[1] *The effect of convertible debentures has been excluded for 2007 as it is anti-dilutive.*

(thousands)	**2007**	2006
Weighted average number of units – basic	61,098	60,604
Additional units if debentures converted[1]	-	2,190
Weighted average number of units – diluted	61,098	62,794

[1] *The effect of convertible debentures has been excluded for 2007 as it is anti-dilutive.*

12. Accumulated distributions to unitholders

	$
Balance, January 1, 2006	131,383
Unitholders' distributions declared and paid	79,354
Unitholders' distributions declared	7,251
Balance, December 31, 2006	217,988
Unitholders' distributions declared and paid	82,548
Unitholders' distributions declared	7,658
Balance, December 31, 2007	308,194

Pursuant to the Fund Declaration of Trust dated April 3, 2003 and its subsequent amendments, the Fund makes monthly distributions to holders of record on the last day of each month. Payments are made on or about the 15th day of the following month.

Distributions are paid from "Cash Flow of the Trust", a term that is defined in the Fund Declaration of Trust dated April 3, 2003. The Board of Directors of the Fund may, on or before each Distribution Record Date, declare payable all or any part of the Cash Flow of the Trust for the Distribution Period. The amount and level of distributions to be made for each Distribution Period is determined at the discretion of the Board of Directors of the Fund. In determining its distribution policy, the Board of Directors of the Fund considers several factors, including the Fund's current and future cash flow, capital requirements, debt repayments and other factors.

13. 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 $5,519 for the year ended December 31, 2007 (2006 – $2,319).

During the year ended December 31, 2007, 237,294 units were purchased on the market at a cost of $4,429 and 191,327 units were settled in cash for $3,472.

(a) Performance Unit Awards

The Performance Unit Awards will vest 100% on the third anniversary of the effective date of each award, July 1, 2005, July 1, 2006 and July 1, 2007. The number of units to be delivered will be determined by the financial performance of the Fund over the three-year period and is 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, 2005 Grant	July 1, 2006 Grant	**July 1, 2007 Grant**	Payout Multiplier
	Less than 1.32	Less than 1.42	**Less than 1.44**	Nil
First range	1.32 - 1.39	1.42 - 1.51	**1.44 - 1.51**	50% - 99%
Second range	1.40 - 1.55	1.52 - 1.71	**1.52 - 1.67**	100% - 199%
Third range	1.56 and greater	1.72 and greater	**1.68 or greater**	200%

As of December 31, 2007, 485,105 Performance Unit Awards (2006 – 529,867) were outstanding: 164,580 effective July 1, 2005, 144,050 effective July 1, 2006 and 176,475 effective July 1, 2007. The compensation cost recorded for these units for the year ended December 31, 2007 was $4,485 using the applicable closing market price of a unit of the Fund (2006 – $1,367).

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

Restricted Unit Awards will vest automatically, over a three-year period from the effective date of the award on July 1, 2005, July 1, 2006 and July 1, 2007, 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, 2007, 92,275 Restricted Unit Awards (2006 – 98,735) were outstanding: 14,167 effective July 1, 2005, 26,333 effective July 1, 2006 and 51,775 effective July 1, 2007. The compensation cost recorded for these units for the year ended December 31, 2007 was $1,034 using the applicable closing market price of a unit of the Fund (2006 – $952).

14. Financial Instruments

Financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, distributions payable, credit facilities, long-term debt, convertible debentures and derivatives held for trading (derivative financial instruments such as foreign exchange contracts, oil price contracts, natural gas price contracts, power price contracts and physical fixed price contracts).

Derivatives held for trading

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.

Natural gas, NGL and crude oil contracts that require physical delivery at fixed prices and do not meet the Fund's expected purchase, sale or usage requirements are accounted for as derivative financial instruments.

On occasions, the Fund will enter into NGL purchase and sale contracts that are settled in a currency other than the currency that are routinely denominated for such commercial transactions. In these instances, the Fund accounts for these non-financial contracts as embedded derivatives.

Derivative instruments held for trading are recorded on the consolidated statement of financial position at fair value. Changes in the fair value of these financial instruments are recognized in earnings in the period in which they arise.

As at December 31, 2007, $3,112 of assets held for trading were included in accounts receivable and $12,566 of liabilities held for trading were included in accounts payable and accrued liabilities. Unrealized (losses) gains, representing the change in fair value of derivative contracts are recorded in Marketing operating revenue and NGL Infrastructure operating expense.

The unrealized (loss) gain relating to derivative contracts were as follows:

Unrealized (loss) gain	**2007**	2006
Marketing	(12,007)	263
NGL Infrastructure	(556)	-

The fair value of the derivatives 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.

As at December 31, 2007	**Carrying Amount $**	**Fair Value $**	**Weighted Average Price $**	**Notional Volume**
Natural gas:				
Buyer of fixed price swaps *(maturing by October 31, 2008)*	(98)	(98)	6.90/GJ	198,000 GJs
Electricity:				
Buyer of fixed price swaps *(maturing by December 31, 2008)*	444	444	55/MWh	21,960 MWhs
NGLs:				
Seller of fixed price swaps *(maturing by March 31, 2008)*	(11,984)	(11,984)	77.97/Bbl	717,345 Bbls
Buyer of fixed price swaps *(maturing by March 31, 2008)*	2,489	2,489	78.43/Bbl	153,999 Bbls
Currency:				
Seller of forward contracts *(maturing by January 25, 2008)*	111	111	1.0199/USD	US$ 6,500
Physical contracts:				
Seller of fixed price forward contracts *(maturing by March 31, 2008)*	(417)	(417)	53.67/Bbl	54,584 Bbls
As at December 31, 2006				
Natural gas:				
Buyer of fixed price swaps *(maturing by March 31, 2007)*	-	(130)	7.78/GJ	90,000 GJs
Electricity:				
Buyer of fixed price swaps *(maturing by December 31, 2008)*	-	1,031	55/MWh	43,860 MWhs
NGLs:				
Seller of fixed price swaps *(maturing by March 30, 2007)*	211	211	72.25/Bbl	450,000 Bbls
Currency:				
Seller of forward contracts *(maturing by January 26, 2007)*	(287)	(287)	1.1477/USD	US$16,350
Physical contracts:				
Seller of fixed price forward contracts	-	-	-	-

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

Fair value

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

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, 2007, the accounts receivable from the two largest customers amounted to less than 1% of accounts receivable (2006 – less than 1%). Revenue from the two largest customers amounted to 15% of operating revenue for the year ended December 31, 2007 (2006 – 11%). With respect to counterparties for derivative financial instruments, 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.

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$240,149 of sales were priced in U.S. dollars for the year ended December 31, 2007 (2006 – US$313,191).

The Fund realized and recorded $930 of foreign currency loss in Marketing operating expenses for the twelve months ended December 31, 2007 (2006 – $742). A further $1,488 of unrealized foreign currency gains were recorded in Marketing operating expenses for the year ended December 31, 2007 (2006 – $784).

Currency exchange risk is actively managed by using forward currency contracts and swaps. Management monitors the exposure to currency exchange risk and regularly reviews its financial instrument activities and all outstanding positions.

Interest rate risk

The majority of the Fund's interest rate risk is attributed to its fixed and floating rate debt, which is used to finance operations. The Fund's remaining financial instruments are not significantly exposed to interest rate risk. The floating rate debt creates exposure to interest rate cash flow risk, whereas the fixed rate debt creates exposure to interest rate price risk. At December 31, 2007, fixed rate borrowings comprised 100% of total debt outstanding (2006 – 67%). The fair value of the senior fixed rate debt at December 31, 2007 was $337,589 (2006 – $224,457) based on third party estimates. The fair value of the Fund's unsecured convertible debentures at December 31, 2007 was $32,078 (2006 – $31,782) as determined by reference to quoted market price for the Fund's debentures.

15. Commitments and contingencies

The Fund, through its operating entities has assumed various contractual obligations and agreements in the normal course of its operations. The agreements range from one to eleven years and relate to the processing of a major oil and gas producer's natural gas and the purchase of 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. At December 31, 2007, the obligations that represent known future cash payments that are required under existing contractual arrangements are as follows:

		Payments Due by Period					
Contractual Obligations	**Total**	2008	2009	2010	2011	2012	After 2012
Long-term debt[1]	335,000	20,000	90,000	52,500	-	-	172,500
Operating leases[2]	33,845	8,749	7,926	6,359	4,964	3,915	1,932
Purchase obligations[3]	-	-	-	-	-	-	-
Total contractual obligations	368,845	28,749	97,926	58,859	4,964	3,915	174,432

[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 lease 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 eleven 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 market prices. The future volumes and prices for these contracts cannot be reasonably determined.*

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.

16. Supplemental cash flow information

Changes in non-cash working capital

As at December 31,	**2007** $	2006 $
Cash provided by (used in):		
Accounts receivable	(92,743)	31,410
Inventory	(22,655)	(2,232)
Other current assets	2,028	(285)
Accounts payable and accrued liabilities	86,806	(22,999)
Changes in non-cash working capital	(26,564)	5,894
Relating to:		
Operating activities	(25,450)	6,545
Investing activities	(1,114)	(651)
Other cash flow information:		
Interest paid	17,381	18,486
Taxes paid	1,839	4,601

17. Segmented Information

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

Year ended December 31, 2007	Marketing $	Gathering and Processing $	NGL Infrastructure $	Corporate $	Total $
Revenue	1,250,541	191,164	71,079	-	1,512,784
Inter-segment revenue	-	(3,674)	(29,969)	-	(33,643)
External revenue	1,250,541	187,490	41,110	-	1,479,141
Operating expenses	(1,205,653)	(103,792)	(24,253)	-	(1,333,698)
Inter-segment expenses	33,643	-	-	-	33,643
External operating expenses	(1,172,010)	(103,792)	(24,253)	-	(1,300,055)
	78,531	83,698	16,857	-	179,086
General and administrative, interest and other	-	-	-	(42,058)	(42,058)
Depreciation and amortization	(3,190)	(28,211)	(9,613)	(1,026)	(42,040)
Accretion expense	(6)	(2,097)	(379)	-	(2,482)
Impairment expense	-	(728)	-	-	(728)
Earnings (loss) before income tax and non-controlling interest	75,335	52,662	6,865	(43,084)	91,778
Income tax (expense) recovery	987	-	(4,680)	(73,300)	(76,993)
Earnings (loss) before non-controlling interest	76,322	52,662	2,185	(116,384)	14,785
Identifiable assets	256,459	782,079	270,160	22,301	1,330,999
Capital expenditures	550	19,585	8,150	694	28,979[1]

[1] *Total capital expenditures include $3,666 relating to the amount allocated to property, plant and equipment as a result of the acquisition of RPLP (see note 18).*

Year ended December 31, 2006	Marketing $	Gathering and Processing $	NGL Infrastructure $	Corporate $	Total $
Revenue	1,161,899	170,184	69,072	-	1,401,155
Inter-segment revenue	-	(3,448)	(29,184)	-	(32,632)
External revenue	1,161,899	166,736	39,888	-	1,368,523
Operating expenses	(1,134,677)	(96,558)	(23,956)	-	(1,255,191)
Inter-segment expenses	32,632	-	-	-	32,632
External operating expenses	(1,102,045)	(96,558)	(23,956)	-	(1,222,559)
	59,854	70,178	15,932		145,964
General and administrative, interest and other	-	-	-	(37,048)	(37,048)
Depreciation and amortization	(3,299)	(27,291)	(8,653)	(600)	(39,843)
Accretion expense	(10)	(1,950)	(297)	-	(2,257)
Impairment expense	-	(373)	-	-	(373)
Earnings (loss) before income tax and non-controlling interest	56,545	40,564	6,982	(37,648)	66,443
Income tax recovery (expense)	(143)	-	(4,133)	6,936	2,660
Earnings (loss) before non-controlling interes	56,402	40,564	2,849	(30,712)	69,103
Identifiable assets	163,826	789,843	261,649	7,694	1,223,012
Capital expenditures	12,040	45,498	14,573	1,757	73,868

	2007 $	2006 $
Marketing revenue derived from export sales to the U.S.	77,583	84,577
Property, plant and equipment located in the U.S.	11,990	11,925

18. Non-controlling Interest

In the first quarter of 2007, a subsidiary of the Fund purchased an additional ownership interest in Rimbey Pipe Line Co. Ltd. for a purchase price of $1,513. In the second quarter of 2007, Rimbey Pipe Line Co. Ltd. was converted to a limited partnership (RPLP) and a subsidiary of the Fund acquired the remaining interest in RPLP for a purchase price of $5,203 bringing the Fund's ownership in RPLP to 100%. The difference between the fair value of the transactions and the carrying value of RPLP's net assets resulted in a difference of $3,666, which was applied to property, plant and equipment. A future tax liability and corresponding increase to goodwill was recorded in the amount of $520. As a result, the non-controlling interest has been removed from the consolidated statement of financial position.

19. Subsequent Events

On January 2, 2008, the Fund completed an internal reorganization of certain of its subsidiaries. As a result of the reorganization, the Partnership is now directly owned by the Fund and KEML no longer has an interest in the Partnership. It is expected that the future income tax liability will increase by approximately $3.5 million in 2008 as a result of the higher future income tax rate applicable to the Fund. This tax rate is approximately 2.5% higher than the future income tax rate recorded by KEML. On January 2, 2008, the Fund's revolving demand facility with the Toronto Dominion Bank was increased from $10,000 to $15,000. The terms of the facility, including interest rates charged, remain unchanged.

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
Executive Director
and Deputy Chairman
National Grid plc
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
Smiths Cove, Nova Scotia

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

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

(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*

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,
Foothills Region

Steven B. Kroeker
Vice President,
Corporate Development

Bradley W. Lock
Vice President,
North Central Region

David A. Sentes
Vice President,
Comptroller

Head Office

Suite 600,
Sun Life Plaza West Tower
144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4

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

Stikeman Elliott LLP
Calgary, Alberta

Annual Meeting of Unitholders

May 13, 2008, 2:00 p.m.
Sun Life Plaza Conference Centre
144 – 4th Avenue S.W.
Calgary, Alberta

Investor Relations

John Cobb
Director, Investor Relations

Bradley White
Investor Relations Advisor

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Website

www.keyera.com

Stability Rating

Standard & Poor's SR-3

2007 Trading Summary

Units Outstanding:
61.6 million (December 31)

Average Daily Trading Volume:
127,071 units

Trading Prices:
High: $20.11
Low: $15.51
Close: $19.90 (December 31)

END