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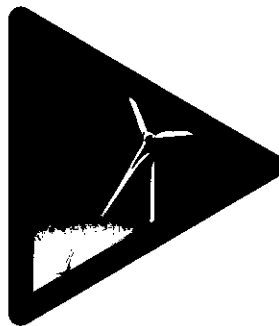
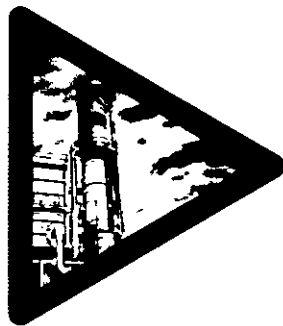
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WHAT'S NEXT.

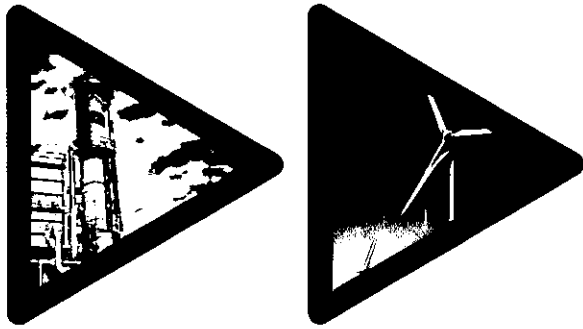


AltaGas

Well connected.

ALTAGAS INCOME TRUST

2007 ANNUAL REPORT

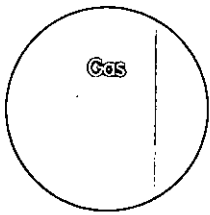


Growth

Sustainable, balanced growth of our energy infrastructure business.

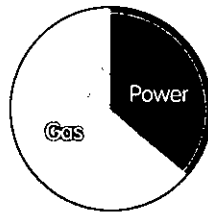
Our goal is to build long-term, sustainable value for our investors. To achieve this, we focus on disciplined and balanced growth in energy infrastructure assets and services, including renewable energy.

1996



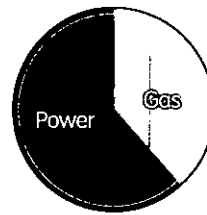
\$2.9 million
operating income
predominantly from
natural gas gathering
and processing and
gas services.

2002



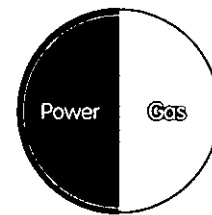
\$61.0 million
operating income from
natural gas gathering
and processing,
extraction and
transmission, natural
gas distribution, energy
services and AltaGas'
first investment in power
generation.

2007



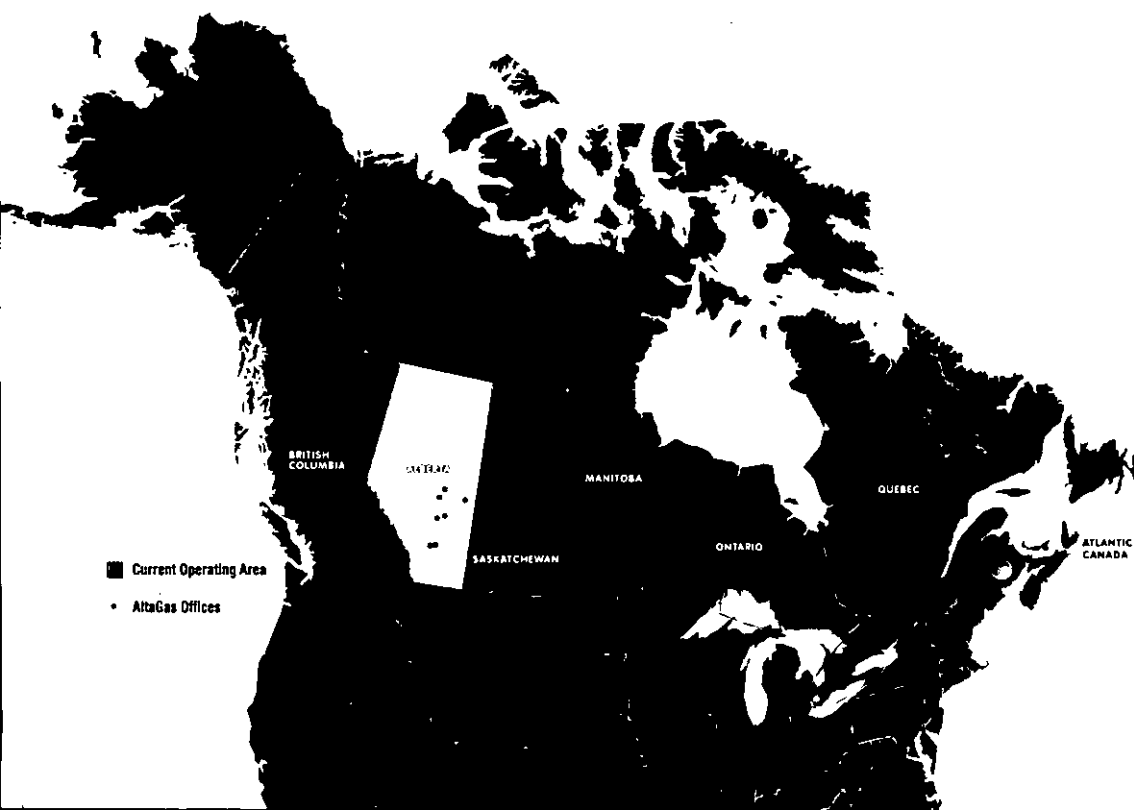
\$126.6 million
operating income from
AltaGas' gas and power
businesses. The gas
business includes extraction
and transmission, natural
gas gathering and
processing and energy
services. The power
business includes coal-fired
and gas-fired generation as
well as current development
plans to spend
approximately \$400 million
on 175 MW of renewable
energy initiatives.

FUTURE



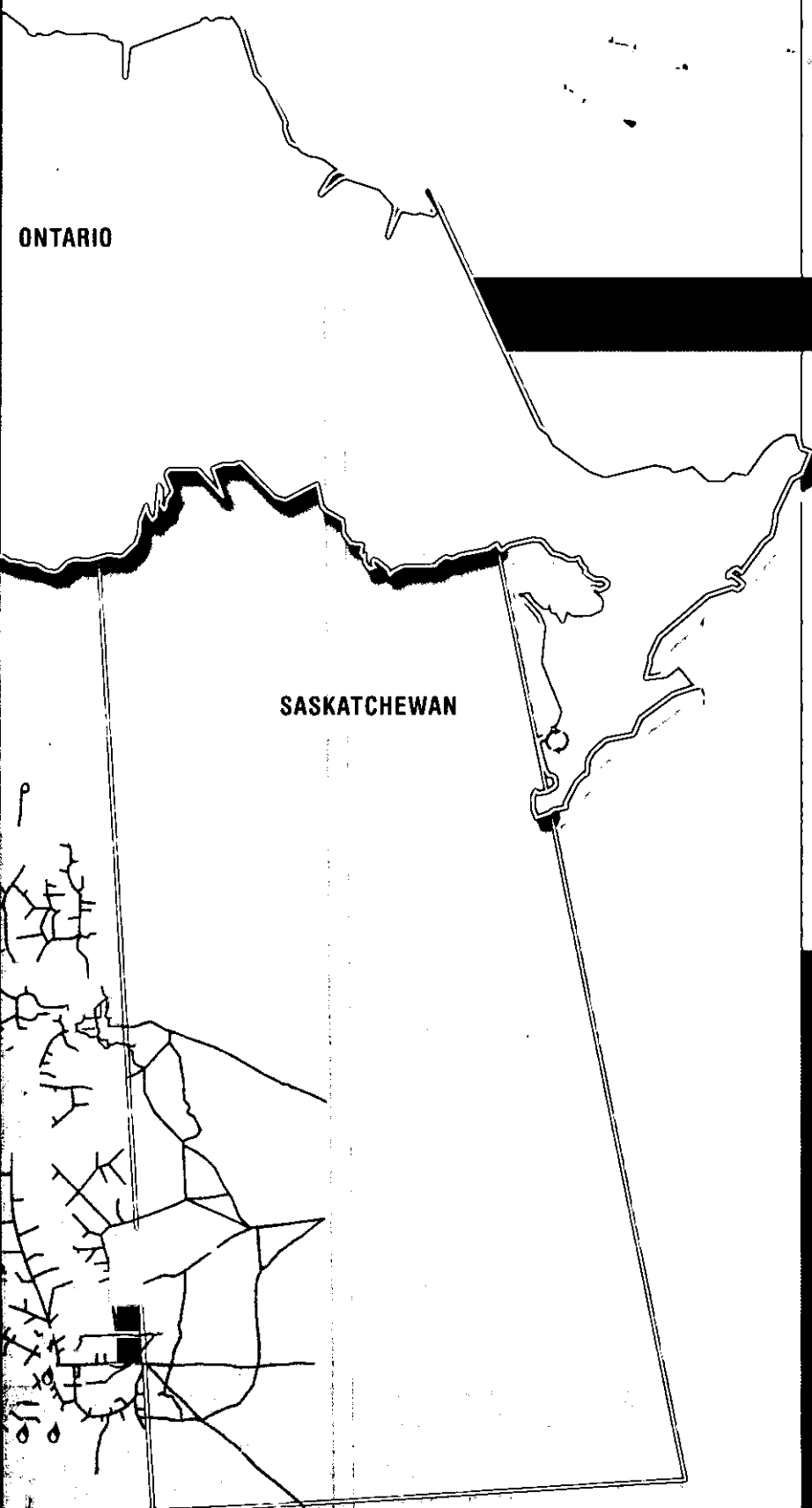
AltaGas' business is
balanced between
natural gas and
power infrastructure
to ensure strong,
sustainable results.

Current Areas of Operation



Contents

IFC	Growth
1	Asset Map
4	Strength
6	Strategy
8	NEXT for Gas
10	NEXT for Power
12	Letter to Unitholders
16	Corporate Governance
18	Management's Discussion & Analysis
63	Management's Responsibility for Financial Statements
63	Auditors' Report
64	Consolidated Financial Statements
68	Notes to the Consolidated Financial Statements
92	10-year Review
94	Unitholder Information
IBC	Corporate Information



AltaGas Assets

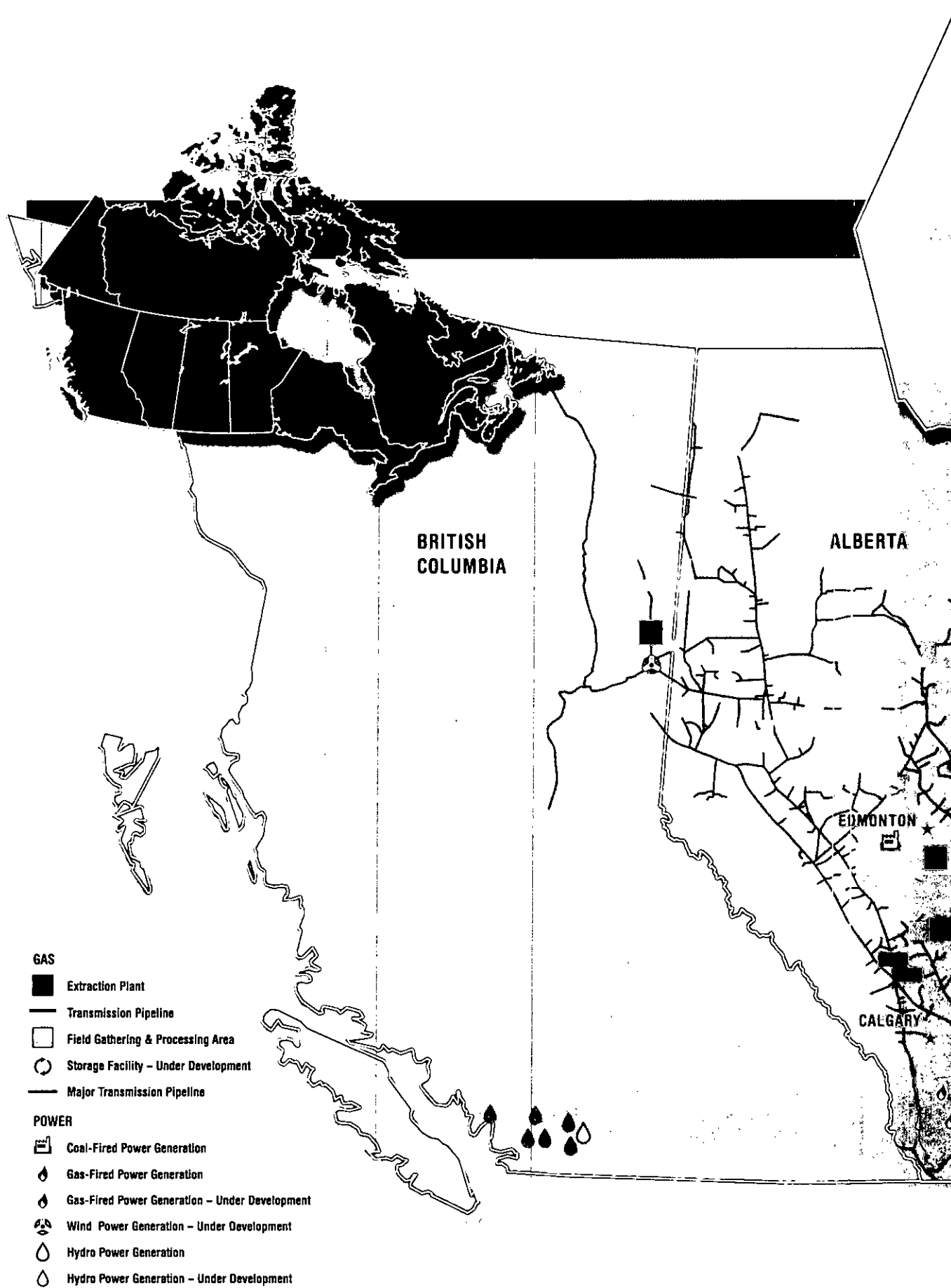
Gas

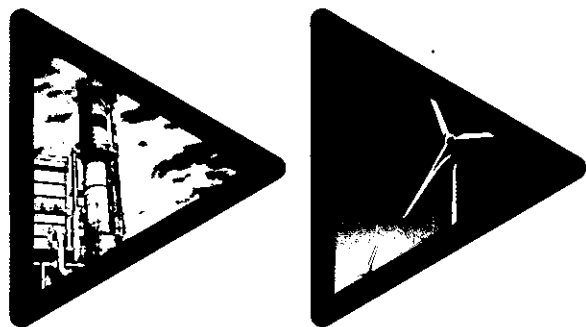
Composed of diversified and integrated infrastructure touching more than 2 Bcf/d of natural gas.

AltaGas' gas infrastructure assets include:

- Interests in six of Canada's 10 NGL extraction facilities with 1.6 Bcf/d of inlet capacity and 86,000 Bbbls/d of NGL production capacity, making AltaGas a leader in extraction. AltaGas operates four of these extraction facilities;
- Transmission pipelines with 554 Mmcfd of gas transport and 151,600 Bbbls/d of NGL transport capacity;
- 77 gas processing facilities with 1.2 Bcf/d of capacity and approximately 6,500 km of gathering lines; and
- A 50 percent interest in the Sarnia Airport Storage Pool project, a 5.3 Bcf natural gas storage project under development in Ontario.

As at March 3, 2008.





Strength

Financial Highlights

(\$ millions except as indicated)

	2007	2006	2005	2004	2003
Revenue	1,428.4	1,362.6	1,502.3	864.6	710.6
Net revenue ⁽¹⁾	324.0	318.9	296.9	250.4	217.3
EBITDA ⁽¹⁾	173.7	173.1	155.5	133.4	121.9
Net income	108.8	114.5	90.3	65.8	38.3
Net income before tax ⁽¹⁾	114.7	113.4	89.0	70.4	61.5
Total assets	1,199.8	1,109.6	1,068.3	1,108.6	919.3
Total debt	220.7	265.5	269.0	359.5	396.9
Debt as a percent of total capitalization (%)	27.4	33.4	36.0	42.6	52.2
Funds from operations ⁽¹⁾	162.9	161.7	129.0	108.6	90.2
Dividends/distributions declared ⁽²⁾	118.6	110.8	100.0	66.7	17.3

\$ per basic unit

EBITDA ⁽¹⁾	3.03	3.12	2.88	2.70	2.68
Net income	1.90	2.06	1.67	1.33	0.84
Net income before tax ⁽¹⁾	2.00	2.04	1.65	1.43	1.35
Funds from operations ⁽¹⁾	2.84	2.91	2.39	2.20	1.98
Dividends/distributions declared per unit ⁽²⁾	2.065	1.995	1.85	1.31	0.38

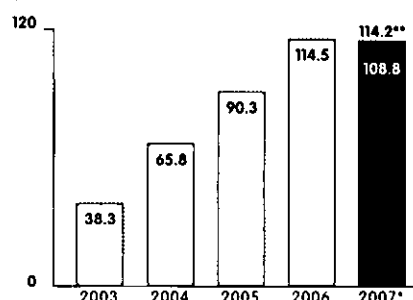
⁽¹⁾ Non-GAAP financial measures. See discussion beginning on page 28 in the Management's Discussion and Analysis.

⁽²⁾ In 2007 distributed an additional \$4.2 million (\$0.076 per unit) in the form of AltaGas Utility Group Inc. shares. In 2005 distributed an additional \$29.3 million (\$0.54 per unit) in the form of AltaGas Utility Group Inc. shares.

We have the financial discipline, strength and flexibility to pursue growth opportunities, while continuing to deliver earnings growth, strong returns on equity and stable distributions.

Regardless of its corporate structure, AltaGas has always focused on traditional financial metrics to deliver strong returns to investors.

Net Income
\$ millions

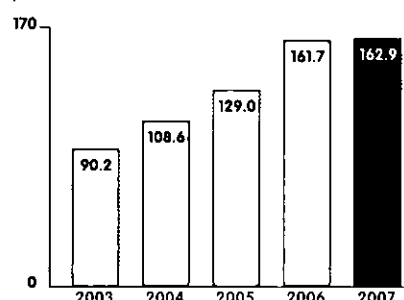


Over the past five years, net income has almost tripled from \$38.3 million to \$108.8 million.

* In 2007 net income included a negative non-cash tax adjustment of \$5.4 million due to SIFT tax. See discussion beginning on page 24 in Management's Discussion and Analysis.

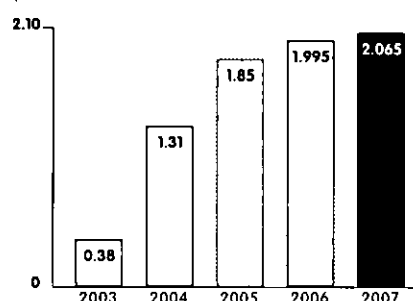
** Figure calculated with adjustment due to SIFT tax.

Funds from Operations
\$ millions



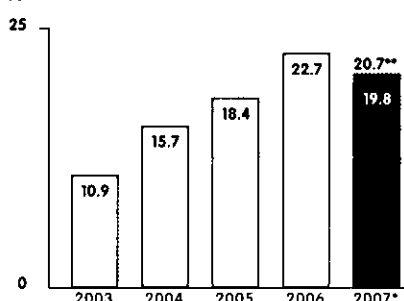
Cumulative average growth of 16 percent in funds from operations from 2003 to 2007.

Cash Dividends/Distributions Declared per Unit
\$



Distributions have increased over the past five years while remaining within conservative payout ratios.

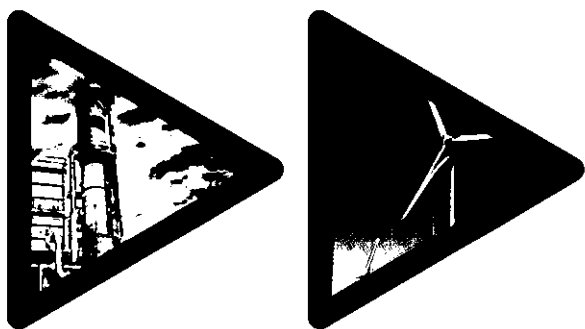
Return on Equity
%



Return on equity has increased almost 9 percentage points over the past five years, from 10.9 percent to 19.8 percent.

* In 2007 return on equity was negatively impacted by the non-cash tax adjustment due to SIFT tax.

** Figure calculated with adjustment due to SIFT tax.



Strategy

Our strategy is working. AltaGas is growing its energy infrastructure business. Our growth will be balanced between our gas and power businesses, diversified geographically and by fuel source. We focus on assets that are complementary to our existing businesses: low-risk, long-life and profitable, including renewable energy sources. We grow where it makes sense – where the assets contribute long-term, sustainable value to our investors.

strategies

Discipline

Focus on disciplined financial strategy and targets to maintain balance sheet strength and financial flexibility to support future growth.

Balance

Balance growth in gas and power over time to mitigate risks, while maintaining the appropriate risk-return balance. Increase value and profitability of existing assets.

Diversification

Seek new opportunities to complement current assets and diversify geographically, by contract type and fuel source – pursuing gas, coal and renewable energy opportunities.

2007 progress

Distributions increased, while remaining within a conservative payout ratio.

Operating income and return on equity continued to be strong.

DBRS and S&P recently affirmed our investment-grade credit ratings.

With the acquisition of Taylor NGL Limited Partnership, remain within our target debt-to-capitalization range.

Initiated the acquisition of Taylor NGL Limited Partnership, adding low-risk, long-life complementary assets, further balancing AltaGas.

Gas business: entered gas storage in Ontario; added two coal bed methane (CBM) processing facilities and a gathering pipeline; completed Cold Lake Orion project; optimized existing field gathering and processing facilities; and divested non-core oil and gas production assets.

Power business: acquired additional gas-fired peaking capacity; began construction of Bear Mountain Wind Park in B.C.; and acquired interest in run-of-river hydroelectric generation and projects in B.C.

Executed our strategy of adding assets in different geographic locations with complementary contractual terms and diversifying our power business by fuel type.

Added incremental gas-fired peaking capacity. Began construction of Bear Mountain Wind Park in B.C.

Acquired run-of-river hydro interest and development projects in B.C. through the acquisition of Taylor NGL Limited Partnership.

Made our first move into natural gas storage, acquiring an interest in a storage project in Sarnia, ON.

what's NEXT

Regardless of our corporate structure, continue to focus on traditional financial metrics – earnings and return on equity – as well as maintain a strong balance sheet and investment-grade credit ratings. Maintain our conservative payout ratios and grow earnings faster than distributions.

Our financial discipline and effective risk management strategies provide us with the flexibility to grow our business, while ensuring stability and growing returns for our investors.

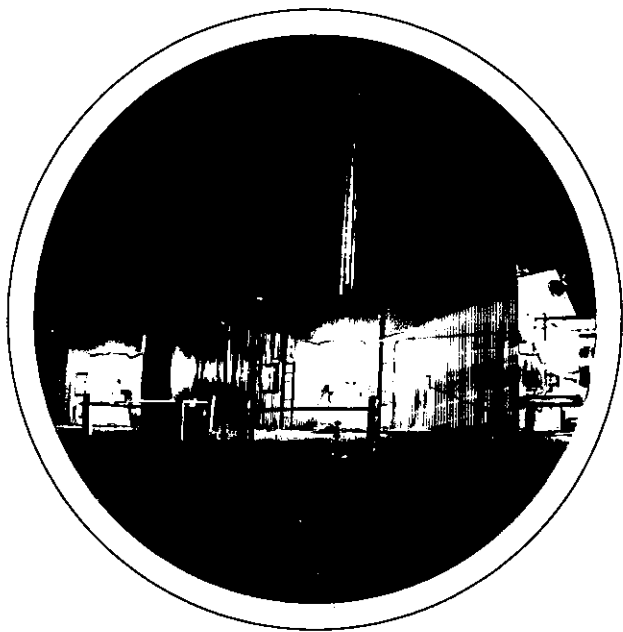
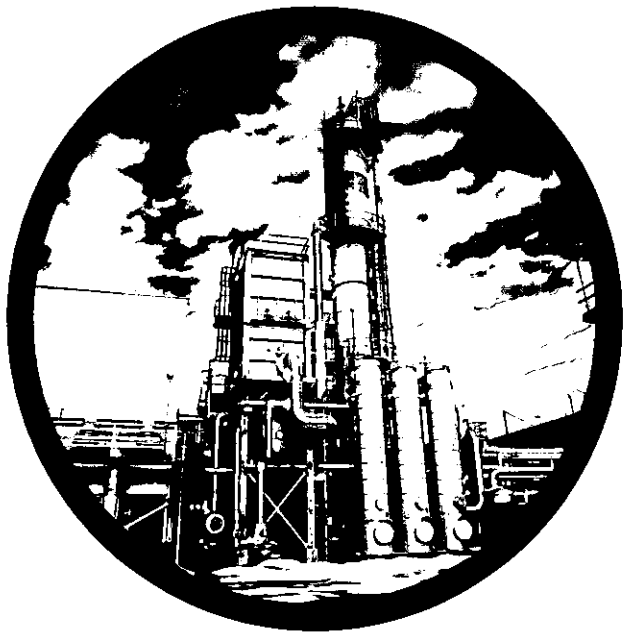
Balance growth in gas and power infrastructure to ensure a strong, sustainable business. Continue to optimize existing infrastructure and services.

Current growth plans include investment in both gas and power projects. The magnitude of the investment in gas and power assets will vary from year to year. Over time growth will be balanced across both businesses.

Diversify AltaGas' asset base geographically and by fuel source with stable, low-risk assets backed by long-term contracts with creditworthy counterparties.

Acquire and develop renewable energy projects, such as wind power and run-of-river hydroelectricity.

Exploit new gas opportunities that complement our current operations, such as Harmattan Co-streaming and additional gas storage.



▶▶ **NEXT for gas**

Integrated gas businesses provide internal growth opportunities and strengthen overall business

Our gas businesses are interrelated and linked to our power business. This integration, combined with our strong market knowledge, expertise and diversified market presence, creates a stronger AltaGas.

Links between the gas businesses create value, allow us to better manage our risk-reward profile, and provide internal growth opportunities, such as the Cold Lake Orion project.

Opportunities exist to expand, grow and optimize our current infrastructure to increase value and profitability.

Diversified business segments and contracting strategy mitigate exposure to commodity prices

The natural gas business is cyclical. The various parts of AltaGas' gas business balance one another, enabling growth in some areas when others experience weakness.

In 2007 lower natural gas prices and regulatory issues led to lower field gathering and processing activity. These low gas prices and continued high oil prices drove fractionation (frac) spreads to historically high levels that increased profits in our extraction business.

AltaGas' contracting strategy focuses on cost-of-service, fixed-fee and margin-based contract terms with minimal or managed exposure to commodity prices, flowing operating costs through to customers and ensuring recovery of invested capital.

Pursue new gas opportunities that build on and complement our current business

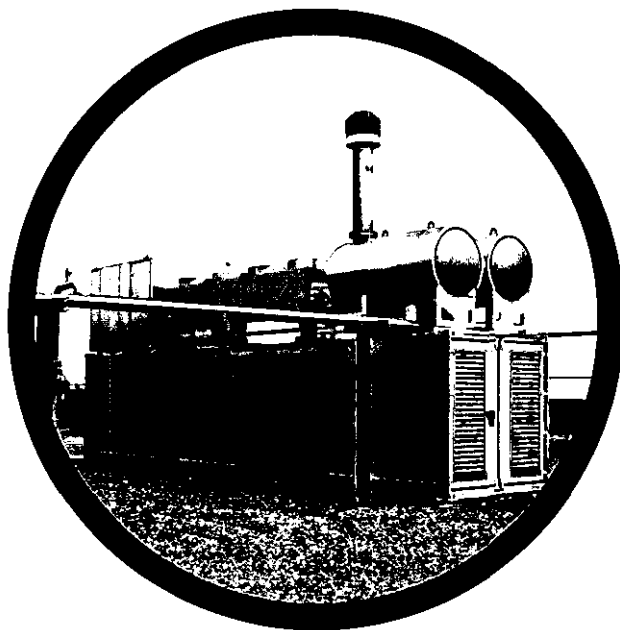
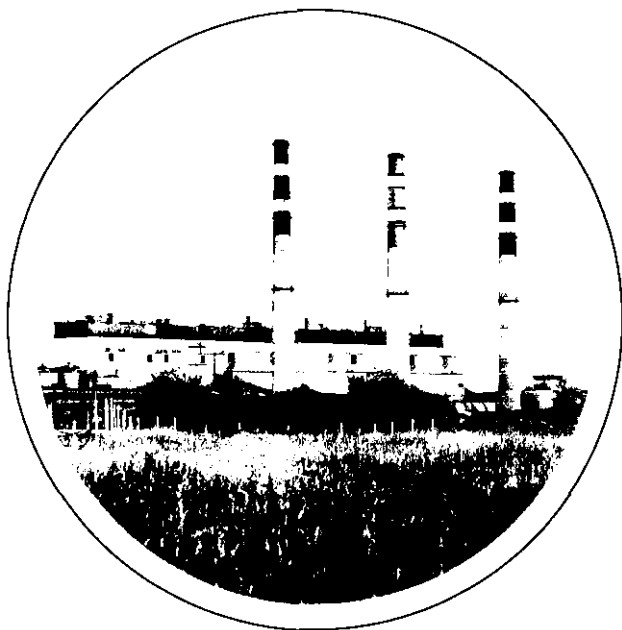
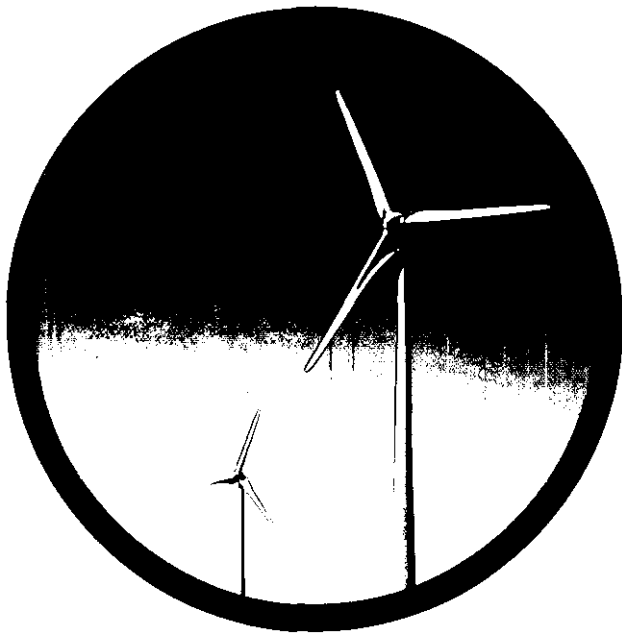
Our growth strategy involves investments in new businesses that capitalize on linkages between our operating experience, market knowledge and financial strength.

In 2007 AltaGas moved into natural gas storage with the acquisition of an interest in the Sarnia Airport Storage Pool Project, allowing us to participate in the growing demand for storage services. We are pursuing additional storage opportunities.

The acquisition of Taylor provides AltaGas with low-risk, long-life complementary assets that increase diversification and better balance AltaGas' asset base. The acquisition also adds significant growth opportunities, such as Harmattan Co-streaming and consolidation of processing capacity in areas served by these new assets.

Focus on active gas production areas and unconventional gas sources

AltaGas continues to expand, construct and acquire processing facilities. We are primarily focused on prolific areas with strong producer activity, like northwest Alberta and northeast British Columbia, and unconventional gas sources, particularly coal bed methane.



▶▶ **NEXT for power**

Successful risk mitigation strategy

AltaGas' strategy is to hedge two-thirds of the Sundance B PPAs' annual output. We continually evaluate opportunities to increase earnings through additional hedging activities as market conditions permit.

We operate our gas-fired peaking plants from our Edmonton extraction facility. These plants ramp up quickly, allowing AltaGas to offer power into the Alberta grid when it is profitable and backstop our coal-fired capacity.

Peaking plants also provide ancillary services to the Alberta power grid – we receive payment for remaining on standby, ready to produce power when dispatched by the grid.

Strong outlook for Alberta power market

Power demand in Alberta remains strong. With limited new generation being built, reserve margins continue to tighten and power prices are expected to remain high for the next few years. This should allow AltaGas to continue hedging at strong prices. In early 2008 forward prices for power in Alberta through 2012 are all in the low to mid-\$70/MWh range.

Increase balance and diversification of power generation portfolio

AltaGas is focused on the long-term sustainability of our power business. We are expanding our power portfolio and diversifying by geography and fuel source.

We entered the power business in 2001 with the acquisition of 353 MW of coal-fired generation in Alberta through a 50 percent interest in Sundance B PPAs. Today, we have a power portfolio consisting of coal-fired, gas-fired and hydro generation, with wind power and more hydro facilities under development in B.C.

Expand into renewable energy sources

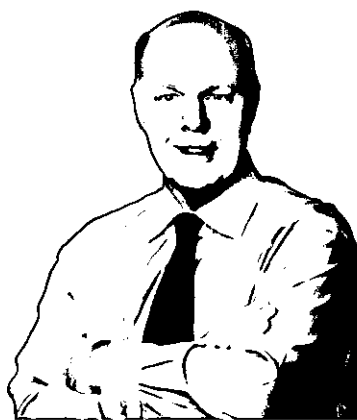
We aim to capitalize on the growing North American demand for clean power. We are expanding into renewable energy sources, such as wind and run-of-river hydro generation, and increasing our development and operating expertise.

The renewable energy projects we pursue are stable, low-risk projects backed by long-term contracts with creditworthy counterparties and strong supply and demand fundamentals.

Integrate with gas business to provide increased growth opportunities

Our power business is closely linked to our gas business. This integration, combined with our strong market knowledge, expertise and diversified market presence, creates a stronger AltaGas.

The links between our gas and power businesses create value, allow us to better manage our risk-reward profile, and provide internal growth opportunities such as the gas-fired peaking plants, which are operated from our Edmonton extraction facility using gas provided by Energy Services.



David W. Cornhill
Chairman and Chief Executive Officer

Letter to Unitholders

Financial discipline, profitable growth and diversification – that's the way AltaGas does business.

In 2007 we clearly demonstrated the "Energy to Grow" that we had promised. We did what we said we would do, executing our strategy for balanced growth in our two businesses, natural gas and power. We continued to create long-term value for unitholders while maintaining the discipline and focus that got us where we are. AltaGas came out of 2007 with the momentum and ability to achieve what's next: further growth in 2008 and beyond.

Our growth strategy is built upon several essential elements. In expanding our assets, the goal is to achieve balanced growth in the natural gas and power businesses while diversifying the cash flow-generating assets within and among our business segments. Diversification includes moving into renewable energy opportunities. As we implement our growth initiatives we will maintain financial discipline, including a strong balance sheet and investment-grade credit ratings. These elements are aimed at growing AltaGas' net income and cash flows year by year, supporting sustainable cash distributions to our unitholders.

Last year we focused on carrying out our growth strategy. We made excellent progress in a number of areas, including:

- Initiating the acquisition of Taylor NGL Limited Partnership, a \$599 million transaction that provides additional growth opportunities while strengthening and diversifying AltaGas in its core businesses.
- Growth in renewable energy, including construction launch of the Bear Mountain Wind Park and initiating the acquisition of our first interest in run-of-river hydroelectric power generation.
- A move into natural gas storage, which will add cash flows and benefit from AltaGas' energy services capabilities in Ontario.
- Continued growth in the natural gas and power businesses, adding 15 Mmcf/d of coal bed methane processing capacity, a 15 Mmcf/d natural gas gathering line and developing an additional 14.4 megawatts (MW) of peaking power capacity.
- Strong financial results, including:
 - Net income of \$109 million (\$1.90 per unit). Net of SIFT tax, net income was \$114 million (\$1.99 per unit).
 - Operating income of \$127 million, equalling the record set in 2006.
 - Funds from operations of \$163 million (\$2.84 per unit).
 - Return on equity of 19.8 percent, or 20.7 percent excluding the SIFT tax.
 - Cash distributions of \$2.065 per unit, reflecting the increase to monthly distributions made in September, while remaining within our recently lowered targeted payout range of 65 to 75 percent of funds from operations.
 - A strong balance sheet, maintaining the Trust's investment-grade ratings and providing the financial flexibility to grow.

The Gas and Power Businesses

AltaGas' power business continued to grow as planned throughout 2007. Our major asset, the Sundance power purchase arrangements, continued to provide a growing cash flow stream that is substantially price-hedged. With power prices and demand strong in Alberta, we continued to realize value on our existing gas-fired peaking plants. And we will bring two new peaking plants into service early this year. Operating income from the power business increased by 4 percent year-over-year.

Results in the natural gas business reflected AltaGas' risk-mitigation strategy. Field activity in the upstream natural gas industry was dampened by price weakness and regulatory issues. However, by carefully building a business of offsetting segments, implementing contracts that flow operating costs through to customers, pursuing long-term contracts, carefully managing its balance sheet and cultivating a diversified opportunity base, AltaGas is able to maintain profitability throughout the commodity price cycle. Nowhere was this strategy better shown than in our gas business. Although overall gathering and processing throughput fell in 2007, lower natural gas prices and continued high oil prices drove higher fractionation spreads that increased profits in the extraction business. Some of our frac spread exposure was hedged at historically high prices, solidifying cash flows for the next year. With one segment balancing the other, our natural gas business results were down only 6 percent and were offset by the increase in 2007 power results. Through this coordination and balance between the segments, we continued to grow our core natural gas business.

Despite recent natural gas price weakness, we remain optimistic about the natural gas business in the Western Canada Sedimentary Basin. We're confident in the ingenuity of Western Canada's energy industry, which is applying bold thinking and creativity to generate new natural gas potential and maximize the basin's reserves. We foresee essentially steady production from Western Canada for many years, creating an environment in which AltaGas can thrive and grow.

Taylor Acquisition

Each of our business efforts in 2007 reflected and advanced our strategy for balanced growth. The largest transaction we undertook in 2007 was the acquisition of Taylor NGL Limited Partnership for \$599 million, excluding our pre-existing 9 percent ownership interest. With its strong 2007 performance, we paid approximately 10 times EBITDA for Taylor. AltaGas will benefit from continued high frac spreads,

AltaGas is able to maintain profitability throughout the commodity price cycle.

The Taylor acquisition adds low-risk, long-life complementary assets that make AltaGas increasingly diversified and balanced.

integration, and significant future growth opportunities resulting from the transaction.

Operationally, the Taylor acquisition adds low-risk, long-life complementary assets that make AltaGas increasingly diversified and balanced. The assets have rated economic lives extending as far as 2050 and in many cases are anchored by long-term contracts of up to 40 years, meeting AltaGas' high standards for long asset life and managed risk. These assets substantially increase cash flows in the Extraction

and Transmission segment, and provide improved balance across AltaGas' business segments.

Financially, the new assets are immediately accretive to AltaGas' cash flow per unit, add free cash flow (roughly, cash flow available for reinvestment) and are expected to be neutral to accretive to net income per unit in 2008. They also increase AltaGas' liquidity and access to capital; important factors as we plan our approach to the post-2010 income trust world.

Additional Growth

We undertook several other initiatives in 2007 that are aligned with our strategy for balanced growth.

We expanded our gas business in Ontario with the addition of natural gas storage, acquiring a 50 percent partnership position in a storage facility in Sarnia with a working capacity of 5.3 Bcf. Storage is a critical service required by natural gas liquids and petrochemical industries and Sarnia is a key location for these businesses. The project provides

steady fee-for-service cash flows that minimize commodity price risk and is expected to be in service in mid-2009. By using the capabilities of the AltaGas Energy Services team in Chatham, Ontario, we can create additional value from this long-life asset. We are also pursuing further natural gas storage opportunities in Ontario and Michigan.

In the gas business we also constructed a new 10 Mmcf/d coal bed methane processing facility in the Horseshoe Canyon formation, acquired a 5 Mmcf/d coal bed methane processing facility in the Mannville formation, both in central Alberta, and acquired a 15 Mmcf/d natural gas gathering line.

In the power business, we began the installation of two additional peaking facilities with combined output of 14.4 MW. Peaking plants are small, natural gas-fired generators used to top up a region's electricity supply in times of maximum demand. The new plants are located at two of our existing field gathering and processing facilities, and all six of our peaking plants will be controlled from our Edmonton extraction

facility. This is an excellent and highly profitable demonstration of integrating our assets and services across our business segments to create additional value. The peaking power business uses existing assets as a base, and improves AltaGas' market presence, physical infrastructure and expertise. This business backstops our coal-fired Sundance power purchase arrangements and is also used to provide backup services to the Alberta power market.

Renewables

AltaGas' careful and deliberate move into renewable energy development is another compelling example of our balanced growth. Renewable energy is helping diversify our power business by energy source and geographic location. With approximately 175 MW of run-of-river hydro and wind power generation under development or construction, we are evolving into a major renewable energy player, particularly in British Columbia.

December marked an important milestone, commencing construction of the Bear Mountain Wind Park. I'm proud of Bear Mountain. This \$190 million project will have the capacity to produce approximately 100 MW of clean, green power when it enters service in late 2009 - helping BC Hydro meet its commitment of 90 percent of new capacity generated from green sources. The gearless turbines that we ordered from Enercon are efficient, cost-effective and reliable. Bear Mountain will be B.C.'s first wind farm and its output will be sold to BC Hydro under a 25-year, indexed contract. We also own a 25 percent interest in a run-of-river hydroelectric project that generates 7 MW of clean, sustainable electricity backed by a long-term contract with BC Hydro. We have a pair of 40-year contracts with BC Hydro for two 10-MW run-of-river projects which should be in service in 2010, and in February 2008 we announced an additional four potential run-of-river projects totalling approximately 50 MW of capacity.

Financial Performance

The fundamental purpose in executing our growth strategy is to increase our net income and cash flows, and to create long-term value for unitholders. AltaGas had a fantastic year in 2006 with all-time record results, and I'm pleased that in 2007 we were able to meet that performance. Even more important was the way we achieved these results. Since 1994 we have worked to build a business that is viable and strong for the long term. We have a track record of 14 years of increasing cash flows. We focus on mitigating risks and securing long-term revenue streams to make cash flows stable and predictable. As we add new assets and new lines of business, we look for ways to mitigate downsides. We reduce cost

exposure and throughput risks in the natural gas business, for example, by structuring services around flowthrough contracts. In extraction we gain exposure to frac spread upside but have downside protection for when these spreads are unfavourable. We underpin our power business with price hedges.

These were the basic, foundational measures selected when we began business. By using them to guide our performance, these measures have helped us create tremendous value over the years. Meanwhile, we added a further layer of risk-mitigation by structuring a diversified overall business, resilient to movements in individual segments. We have delivered on our goal of

securing long-term cash flows. Consequently, AltaGas has proven to be a good investment. We increased net income nearly six-fold from 2001 through 2006, and last year matched our record 2006 operating income. These strengths enabled AltaGas to increase its monthly distribution by 3 percent to \$0.175 per unit last September, while remaining within our recently lowered targeted payout range of 65 to 75 percent of funds from operations.

People, Safety and Community

People are a key focus at AltaGas - both our employees and those in the communities we operate. The quality of our workforce is one of the three key priorities in our strategic plan. I was pleased to see that in October, AltaGas was again recognized as one of Canada's top 100 employers. It was our sixth year in a row, something only one other organization in Calgary can match. This recognition not only allows us to benchmark ourselves within the business community, but it's a real competitive advantage in attracting the right people. By emphasizing

opportunity, challenge and competitive compensation, AltaGas aims to create a favourable work environment, thereby motivating high-quality people to join AltaGas and build careers here.

Our contributions in the communities where we live and operate are focused, carefully selected, and long term. We also provide support to a wide range of organizations on a smaller scale. Our long-term commitments enable us to have a major impact on our partner organizations, the people they support, our employees and the communities around our offices and field facilities. This thinking formed the basis of our five-year, \$300,000 commitment to the Alberta-based Shock Trauma Air Rescue Society (STARS) and our ongoing employee and organizational commitment to the United Way.

Renewable energy is helping diversify our power business by energy source and geographic location.

Since 1994 we have worked to build a business that is viable and strong for the long term.

AltaGas' concern for employees and communities is a clear reflection of our number one core value, safety and environment. The potentially life-saving safety benefits are one reason for our involvement with STARS. Our financial support assisting STARS to acquire new air ambulance helicopters with extended range that can provide rapid response to people in need - including the approximately 350 individuals working at our field facilities in B.C., Alberta and Saskatchewan.

Last year we commenced another multi-year commitment, the sponsorship of Canada's national cross-country ski team. We feel an affinity to this sport's values of focus, discipline and long-term commitment to achieving a goal. These values fit our own culture, and we are pleased to make a four-year commitment totalling more than half a million dollars. These funds will help develop Canada's national cross-country ski team, including the hiring of additional coaches who will focus on building Canada's amateur talent to an internationally competitive level. This national sponsorship also creates coast-to-coast exposure of the AltaGas name, matching our coast-to-coast business presence.

Regulatory

AltaGas' confidence, capabilities, diversified businesses and financial strength provide many benefits, including positioning AltaGas to deal with changes to the fiscal and regulatory environment. New policies from the federal and provincial governments were imposed in 2007 that added higher levels of uncertainty, and created unsupportive impacts on businesses. Key provisions of the higher Alberta oil and natural gas royalties program, announced in general terms last fall and to be implemented in 2009, remain unknown. These questions are expected to continue impacting the energy-producing sector in 2008. Our natural gas producer customers need to know the rules in order to calculate costs and, in turn, to plan their capital programs effectively. Additionally, the provincial government's new policy demanding that industries decrease carbon dioxide emissions intensity, coupled with an as-yet incomplete plan for greenhouse gas credits, creates further uncertainty for Alberta business and all Canadians. It's imperative that governments of all levels provide regulatory clarity in these areas.

We have repeatedly stated that, having thrived as a corporation before our 2004 trust conversion and having a steady focus on the key financial metrics of net income and return on equity - as a leading corporation would - we are comfortable about returning to a corporate structure after 2010, should it make economic sense. AltaGas' business

growth, earnings record, distributions strength, comfortable payout ratio, strong balance sheet and tax pools to help shelter future earnings, leave us well-prepared for the post-2010 environment. When the time comes, we will take the path that is best for our unitholders.

What's NEXT

Our business is solid. Since inception just 14 years ago, AltaGas has grown through good vision, strong leadership, outstanding people, the right assets and focus, and investors who get it. We have become a regional energy infrastructure player with transcontinental business. Looking forward, we will continue to balance growth in gas and power. We will continue our focus on renewable energy, and will broaden our reach, both geographic and by fuel source, with investments such as natural gas storage and our significant and leading commitment to renewable energy developments in B.C. and other areas in Canada and the northern United States.

We will remain guided by the core values that have developed AltaGas into what it is today - a market leader and proven innovator.

We will remain guided by the core values that have developed AltaGas into what it is today - a market leader and proven innovator. Every asset we build or buy will meet our key criteria and must contribute to creating long-term value for unitholders, while maintaining or improving our risk profile, balance sheet strength and ability to grow net income,

funds from operations and return on equity. AltaGas will continue to pursue its goal of growing net income faster than distributions.

Financially we are well-positioned to execute our strategy. With a strong balance sheet, access to credit, increasing free cash flow and a universal shelf prospectus for \$500 million in new equity or debt if needed, AltaGas has the resources to grow.

Finally, I would like to express my thanks to every AltaGas employee for their dedication and focus in carrying out AltaGas' strategy for balanced growth throughout 2007 and into 2008. I also welcome the employees and managers of Taylor to our team. The outstanding quality of today's AltaGas team gives me confidence that we will continue creating value for our unitholders tomorrow and well into the future.

On behalf of the Board of Directors,



David W. Cornhill
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

March 3, 2008

Board Of Directors



David W. Cornhill
CHAIRMAN AND CHIEF
EXECUTIVE OFFICER
Member of the EOHSC



Allan L. Edgeworth
DIRECTOR
Independent director;
Member of the AC and EOHSC



Denis C. Fonteyne
DIRECTOR
Independent director;
Chair of the EOHSC and
Member of the HRCC



Daryl H. Gilbert
DIRECTOR
Independent director;
Member of the AC and HRCC

Corporate

The members of the Board of Directors of AltaGas General Partner Inc. are elected by the Trust at the direction of the unitholders to manage or supervise the management, business and affairs of the Trust. It is our responsibility to ensure that the interests of unitholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for stewardship of the Trust and has developed standards and procedures for its operations that meet a high standard of governance. We regularly review the activities of the Trust with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that unitholders expect. We are committed to continuing to direct the activities of the Trust to those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate the Trust's goals and strategy to unitholders. The meeting offers unitholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase unitholder value and grow the Trust. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting either in person in Calgary or through the live webcast that can be viewed at www.altagas.ca. The annual meeting will be held at 3:00 p.m. MDT on Thursday, April 24, 2008 at The Metropolitan Centre, Strand/Tivoli Room, 333 – 4th Avenue S.W., Calgary, Alberta.

On behalf of the Board of Directors:

Myron F. Kanik
LEAD DIRECTOR

AltaGas believes that good governance improves performance and benefits all unitholders. AltaGas is committed to a high standard of governance. The following is a summary of the Trust's Governance Practices. A more detailed description of the Trust's practices can be found in the Trust's Information Circular filed on the SEDAR system.

Statement of Governance Practices

Mandate of the Board

The Board of Directors of the General Partner exercises overall responsibility for the management and supervision of the affairs of the Trust. This includes the appointment of the Chief Executive Officer and senior officers of AltaGas Ltd. and AltaGas General Partner Inc., approval of their compensation and monitoring of the Chief Executive Officer's performance.

The Board of Directors also reviews and approves the annual strategic plan. Key objectives, as well as quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

The Board of Directors ensures that a process is established that adequately provides for succession planning, including the appointment, training and monitoring of senior management.

In 2007, the Board of Directors reviewed and ratified the Trust's Disclosure Policy.

Board Composition

The Board currently comprises eight Directors, seven of whom are independent. David W. Cornhill, Chairman and Chief Executive Officer of AltaGas General Partner Inc., is the only member of the Board of Directors who is also a member of management.



Robert B. Hodgins
DIRECTOR
Independent director;
Chair of the AC and Member of the GC



Myron F. Kanik
LEAD DIRECTOR
Independent director;
Chair of the GC and of the HRCC



David F. Mackie
DIRECTOR
Independent director;
Member of the GC and HRCC



Neil McCrank
DIRECTOR
Independent director;
Member of the GC and EOHSC

governance

Board Committees

The Board has four standing committees: Governance; Audit; Environment, Occupational Health and Safety Committee; and Human Resources and Compensation. The Governance, Audit and Human Resources and Compensation committees are composed exclusively of non-management, independent directors. The Environment, Occupational Health and Safety Committee includes a majority of non-management, independent directors. The Chairman and Chief Executive Officer of AltaGas General Partner Inc. serves on the Environment, Occupational Health and Safety Committee. Each of the committees has a Board of Directors-approved mandate that prescribes its composition and responsibilities.

Governance Committee (GC)

The Governance Committee is responsible for reviewing, reporting and providing recommendations for improvement to the Board with respect to all aspects of governance. The Committee is responsible for identifying individuals qualified to become members of the Board of Directors, and recommends to the Board of Directors proposed nominees for election to the Board of Directors. The Committee reviews and recommends compensation for Directors. Annually, the Governance Committee formally assesses the effectiveness of the Board of Directors and the Committees of the Board of Directors. As well, the Committee is responsible for the orientation and education of new members of the Board of Directors and continuing development of existing members of the Board of Directors.

Audit Committee (AC)

The Audit Committee comprises three independent and financially literate Directors who oversee the Trust's financial reporting process on behalf of the Board of Directors. The Audit Committee reviews, reports and provides recommendations to the Board of Directors on the

annual and interim financial statements, including the completeness and accuracy of financial reporting of the Trust; the adequacy of risk management processes; the adequacy of its internal control system for financial reporting and disclosure; and the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every Audit Committee meeting, the Committee has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the Audit Committee is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada PipeLines Limited. Mr. Hodgins has the strong financial background crucial to this role.

Environment, Occupational Health and Safety Committee (EOHSC)

The Environment, Occupational Health and Safety Committee is responsible for reviewing, reporting and making recommendations to the Board of Directors on the Trust's policies and procedures with respect to the environment and occupational health and safety.

The Trust is committed to being a steward of the environment and to the health and safety of its employees.

Human Resources and Compensation Committee (HRCC)

The Human Resources and Compensation Committee reviews, reports and provides recommendations to the Board of Directors on the compensation of the Chief Executive Officer and the appointment and compensation of senior corporate officers, succession plans, the compensation policy for all other employees and the approval of all grants of unit options. In 2006, AltaGas adopted a Code of Business Ethics, a copy of which can be viewed on our website. AltaGas is committed to operating its businesses in an ethical manner.

Financial growth

MD&A Contents

overview

- 21 Overview of the Business and Strategy
- 24 Consolidated Results
- 27 Taylor NGL Limited Partnership 2007 Results
- 28 Non-GAAP Financial Measures
- 30 Results of Operations by Segment

segments

- 30 Field Gathering and Processing
- 35 Extraction and Transmission
- 41 Power Generation
- 46 Energy Services
- 50 Corporate
- 51 Invested Capital

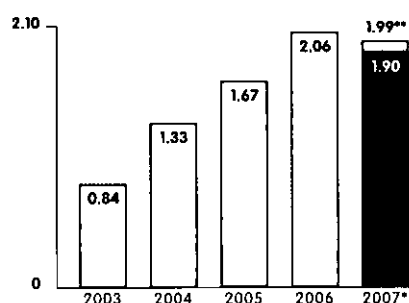
liquidity

- 52 Financial Instruments
- 53 Liquidity and Capital Resources
- 56 Distributions
- 56 Trust Unit Information

other

- 57 Changes in Accounting Policies
- 58 Critical Accounting Estimates
- 59 CEO/CFO Certification
- 60 Subsequent Events
- 61 Fourth Quarter Highlights
- 62 Sensitivity Analysis
- 62 Eight Most Recent Quarters

Net Income per Basic Unit
\$



\$108.8

million
net income

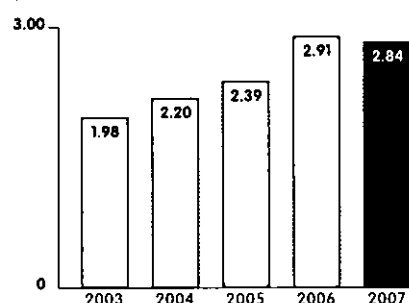
Cumulative average
growth of 23%

* In 2007 net income per unit included a negative non-cash tax adjustment of \$0.09 per unit due to SIFT tax. See discussion beginning on page 24.

** Figure calculated with adjustment due to SIFT tax.

Page 24

Funds from Operations per Basic Unit
\$



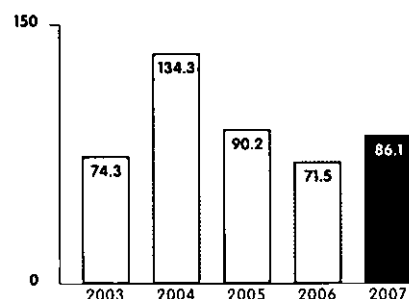
\$162.9

million
funds from
operations

Cumulative average
growth of 10%

Page 24

Invested Capital
\$ millions



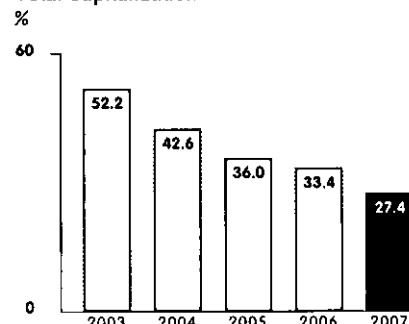
\$1.2

billion
total assets

Total of \$456.4 million
invested in last
five years

Page 51

Debt as a Percent of Total Capitalization
%



\$220.7

million
total debt

Below target of 40-45%
to support growth
strategy

Page 54

2007

key drivers

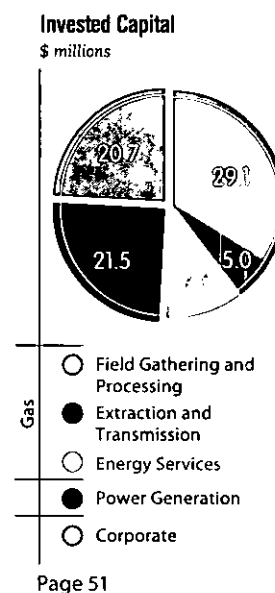
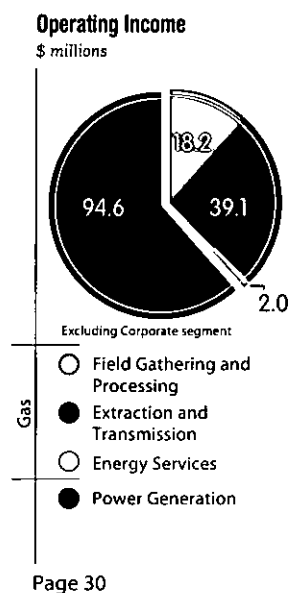
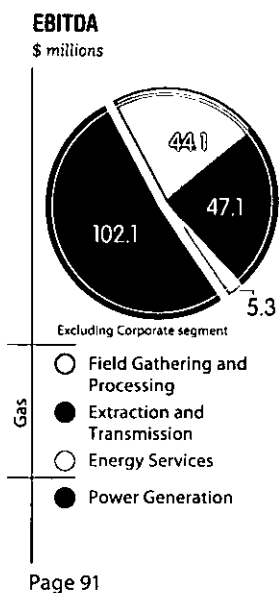
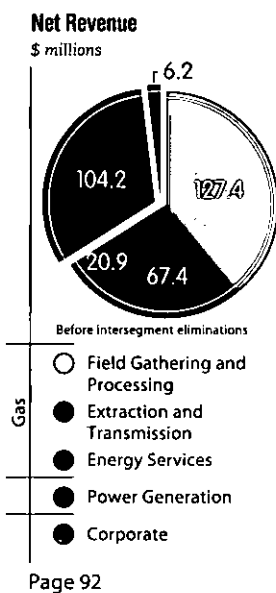
- Higher hedged power prices and lower costs more than offset lower spot power prices and the expiration of the Genesee power contract in 2006.
- Higher frac spreads and volumes increased Extraction and Transmission results.
- Impact of lower throughput in Field Gathering and Processing segment was partially offset by new facilities and higher rates due to recontracting.
- Sale of non-core oil and gas production assets.
- Higher operating and administrative costs.
- Non-cash future income tax benefit of \$6.1 million due to reduced federal tax rates mostly offset the \$5.4 million SIFT tax.

\$324.0
million
net revenue

\$173.7
million
EBITDA

\$126.6
million
operating
income

\$86.1
million
invested
capital



Management's Discussion and Analysis

The Management's Discussion and Analysis (MD&A) of operations and financial statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2007 compared to 2006. This MD&A dated March 3, 2008 should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2007.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this

MD&A, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other for which it is disclosed herein.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of the Trust, including its annual MD&A and audited financial statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's website or directly through the SEDAR system at www.sedar.com.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipelines Partnership, PremStar Energy Canada Limited Partnership and ECNG Limited Partnership (collectively the operating subsidiaries). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is derived from operating income earned from partnership interests held by AltaGas Holdings Limited Partnership No. 1 (AltaGas LP #1), from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the holders of the units, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

OVERVIEW OF THE BUSINESS

AltaGas is a gas and power infrastructure business with physical links along the energy value chain, operating experience that has a strong track record of achieving efficiency, reliability and profitability of its assets, knowledge of the markets it serves and the financial discipline to create long-term value for its investors. AltaGas is focused on maximizing the profitability and long-term value of its current assets and growing its energy infrastructure business through the acquisition and development of assets and services that are linked to its existing business.

The gas business is comprised of gathering and processing assets which include natural gas gathering pipelines and processing facilities. The gathering systems move natural gas from producing wells to processing facilities and the processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation. The processing assets also include ethane and natural gas liquids (NGL) extraction and field fractionation facilities. Extraction plants straddle major natural gas transmission pipelines and reprocess the natural gas to extract and recover ethane and NGLs. The gas business also includes natural gas and NGL transmission pipelines. Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. Another key component of the AltaGas gas business is the ability to use its market knowledge and expertise to optimize the assets to create value. AltaGas provides energy consulting and supply management services to non-residential end-users, buys and resells energy, gas transportation and storage, and markets gas for producers to further enhance value by optimizing the infrastructure.

The power business consists of 353 MW of coal-fired base-load generation acquired under power purchase arrangements (PPAs). The PPAs are owned through a 50 percent ownership interest in the Sundance B PPAs, giving AltaGas the rights to Sundance B power output and ancillary services until December 31, 2020. The Sundance plant is located 70 km west of Edmonton, Alberta. AltaGas' power generation portfolio also includes the Bear Mountain Wind Park near Dawson Creek, British Columbia, which will have a capacity of approximately 100 MW and is currently under construction, 25 MW of gas-fired power peaking capacity acquired under a capital lease, as well as a 25 percent interest in a 7-MW run-of-river hydroelectric generation capacity through a 25 percent interest in the Boston Bar Partnership. AltaGas owns 14.4 MW of natural gas-fired peaking capacity which is currently being installed at two gas processing sites. AltaGas has an interest through the GreenWing Energy Development Limited Partnership (GEDLP) to develop wind power and gas-fired power generation and has a preferred relationship with a major turbine supplier to develop wind projects in three states in the United States. AltaGas also owns lease rights and agreements to develop approximately 70 MW of run-of-river hydroelectric projects.

Vision

AltaGas' vision is to become the leading Canadian energy infrastructure company with a focus across Canada and the northern United States, by capitalizing on its solid underlying business, operational expertise and financial strength. To achieve its vision, AltaGas will focus on increasing the value and profitability of its existing assets and on growing and diversifying through development and acquisition of gas and power infrastructure.

Strategy

The Trust's strategy is to deliver sustainable and increasing earnings and cash flow from its existing assets as well as from the growth and diversification of its business. It will achieve this by linking the operating experience of its gas and power business with its energy market knowledge and financial discipline and strength. AltaGas expects the growth in its business to be evenly split between gas and power over the long term. The strategy is to enhance value by providing value-added services along the energy value chain of gathering, processing, transporting and marketing of natural gas and the generation and sale of electricity.

By positioning the Trust strategically along the energy value chain, AltaGas links energy producers to energy users. AltaGas pursues opportunities that offer strong financial returns and growth potential and identifies, evaluates and targets opportunities that are accretive to earnings and cash flow and that provide the appropriate balance between risk and return.

Despite the softening in natural gas prices over the past 18 months and uncertainty in the Alberta royalty regime, AltaGas management believes that North America's natural gas producing regions will continue to require significant investment in drilling, gathering and processing assets to support the levels of production needed to meet long-term demand for natural gas as consuming markets continue to compete for supply. Management also believes that the long-term fundamentals of the power business are strong. North American demand for power is expected to continue growing, with an emphasis on renewable power. In Alberta, marginal supply additions, strong economic growth and the upcoming retirement of older thermal power plants will likely continue to result in high power prices. The sound long-term supply and demand fundamentals for gas and power form the basis of AltaGas' strategy.

The Trust's objectives are to:

- Maximize the profitability and long-term value of its existing infrastructure and services;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee, and margin-based contract terms and with minimal or managed exposure to commodity prices;
- Grow its gas and power infrastructure and related services through consolidations, expansions and acquisitions in Canada and the northern United States;
- Focus on projects that are accretive to earnings and cash flow and exhibit the appropriate risk and return balance;
- Diversify infrastructure by fuel source, contractual terms, exposure to industry cycles and geographic location;
- Focus on expanding its clean energy footprint such as wind and hydroelectric power, as well as natural gas-fired generation;
- Generate green credits through technology such as acid gas injection and renewable projects to decrease environmental impacts and hedge against environmental costs; and
- Maintain the Trust's investment-grade credit ratings.

In 2007 the Trust made significant progress in growing its business through the offer to acquire Taylor NGL Limited Partnership (Taylor), the expansion of current operations and the development of the Bear Mountain Wind Park. The Taylor acquisition, completed on January 10, 2008, created a more balanced and diversified business with the addition of the RET Complex, the Harmattan Complex, the Younger and Joffre extraction plants as well as two NGL pipelines. The Taylor acquisition also included the 25 percent interest in the Boston Bar hydroelectric plant which increased AltaGas' power generation portfolio by 1.8 MW, as well as two run-of-river hydroelectric projects under development with a planned 20 MW of capacity contracted for 40 years with BC Hydro.

The Taylor acquisition is an example of AltaGas' strategy at work. The newly acquired assets are low-risk, long-life energy infrastructure that are underpinned by long-term contracts with strong counterparties providing stable and predictable cash flows. With the acquisition, AltaGas' infrastructure touches more than 2 Bcf/d of natural gas and AltaGas operates four extraction plants serving the Western Canada Sedimentary Basin (WCSB). The contribution from the extraction business will be increased, thereby diversifying revenue sources. The assets also have the appropriate risk profile, with 12 percent of total extraction volumes exposed to commodity price fluctuations while maintaining the opportunity to limit downside risk and shut-in production when frac spreads are low. AltaGas' new interest in the existing hydroelectric generation plant and run-of-river projects under development have expanded its renewable energy footprint.

Specified Investment Flow-Through (SIFT) Tax and Other

On June 12, 2007 the SIFT tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Prior to this legislation, AltaGas' future income tax liability reflected only those temporary differences in the Trust's subsidiaries that were subject to tax. While net income in 2007 was significantly reduced by this future income tax adjustment, the non-cash future income tax expense had no impact on current cash flows.

In December 2007 the federal government substantively enacted rate reductions which lowered corporate tax rates for the years 2008 to 2012 and beyond. The federal corporate tax rates were reduced from 19.5 percent in 2008 to 15 percent in 2012 and future years. These rate reductions resulted in rate reductions to the trust taxation rate from 31.5 percent as enacted by the federal government in second quarter 2007 for years commencing 2011, to 29.5 percent in 2011 and 28.0 percent thereafter.

AltaGas' management will continue to review and consider alternatives for the most efficient organizational structure for AltaGas. The Trust is registered in Alberta where a corporation is subject to lower overall tax rates than the rate that will apply to trusts in 2011. The federal government has indicated that it will allow corporate conversions to occur on a tax deferred basis but the specific rules have not yet been established. Subject to the tax deferred mechanism being available, AltaGas expects that it will convert to a corporation prior to 2011 but expects to take advantage of the flow-through mechanism of the trust structure until then, unless there are more compelling reasons for converting prior to 2011. AltaGas has always executed its strategy as a tax-efficient corporation and focused on key traditional financial metrics such as earnings per unit and return on equity. It does not rely on the trust structure to sustain its business. Its assets are long-life, low-risk energy infrastructure, the value of which is underpinned by strong energy supply and demand fundamentals. The infrastructure assets generate strong, predictable and sustainable cash flows and are expected to continue to enhance value for all investors over the long term.

2007 Highlights

AltaGas:

- Offered to acquire all the outstanding units of Taylor not previously held by AltaGas. The acquisition was completed on January 10, 2008. The Taylor acquisition increased extraction capacity by 1,040 Mmc/d, added 140,000 Bbls/d in transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing (FG&P) segment's capacity by 150 Mmc/d. In addition, the Power Generation segment increased with the 25 percent ownership of the 7-MW Boston Bar power plant and acquisition of 20 MW of hydroelectric generation under development;
- Announced its first energy infrastructure investment in Ontario with the 50 percent ownership of the 5.3 Bcf Sarnia Airport Storage Pool Project;
- Invested \$28 million in field gathering and processing infrastructure, primarily in coal bed methane producing areas;
- Acquired and commenced installation of 14.4 MW of additional gas-fired peaking capacity at the Bantry and Parkland gas processing facilities;
- Generated net income of \$108.8 million (\$1.90 per unit) compared to \$114.5 million (\$2.06 per unit) in 2006. In 2007 net income included \$5.4 million related to the tax on income trusts which was substantively enacted in second quarter 2007;
- Reported EBITDA of \$173.7 million (\$3.03 per unit), up from \$173.1 million (\$3.12 per unit) in 2006;
- Generated cash from operations of \$183.3 million (\$3.19 per unit) in 2007 compared to \$146.9 million (\$2.65 per unit) in 2006;
- Generated funds from operations⁽¹⁾ of \$162.9 million (\$2.84 per unit) compared to \$161.7 million (\$2.91 per unit) in 2006;
- Increased monthly distributions by 3 percent from \$0.17 to \$0.175 beginning with the September distribution;
- Declared and granted a special distribution of one AltaGas Utility Group Inc. (Utility Group) common share for every 100 trust and exchangeable units of AltaGas valued at \$0.076 per unit;
- Signed agreements with Aeolis Wind Power Corporation (Aeolis) and Peace Energy Renewable Energy Cooperative (Peace) to exchange their equity interests in Bear Mountain Wind Limited Partnership (BMWLP) for a royalty agreement giving AltaGas 100 percent ownership of BMWLP;
- Entered into an engineering, procurement and construction (EPC) agreement with Enercon GmbH for the wind turbines required for BMWLP. AltaGas also entered into a long-term service and maintenance agreement with Enercon to operate and maintain the turbines; and
- Announced a significant multi-year financial commitment valued at more than \$500,000 to support Cross Country Canada. This commitment is the largest philanthropic contribution ever for the Trust and will support the nation's high-performance cross country skiers and fuel their drive to the podium.

⁽¹⁾ Includes financial measures not included under generally accepted accounting principles. Please see discussion in the Non-GAAP Financial Measures section of this MD&A.

CONSOLIDATED RESULTS

Years ended December 31

(\$ millions)	2007	2006	2005
Revenue	1,428.4	1,362.6	1,502.3
Unrealized gains on risk management	1.1	—	—
Net revenue ⁽¹⁾	324.0	318.9	296.9
EBITDA ⁽¹⁾	173.7	173.1	155.5
EBITDA before unrealized gains on risk management ⁽¹⁾	172.6	173.1	155.5
Operating income ⁽¹⁾	126.6	126.7	108.1
Operating income before unrealized gains on risk management ⁽¹⁾	125.5	126.7	108.1
Net income	108.8	114.5	90.3
Net income before tax-adjusted unrealized gains on risk management ⁽¹⁾	109.3	114.5	90.3
Net income before tax ⁽¹⁾	114.7	113.4	89.0
Total assets	1,199.8	1,109.6	1,068.3
Total long-term liabilities	329.0	340.5	335.5
Net additions (disposals) of capital assets	21.8	70.5	(139.4)
Distributions declared ^{(2) (3)}	118.6	110.8	100.0
Cash flows			
Cash from operations	183.3	146.9	112.3
Funds from operations ⁽¹⁾	162.9	161.7	129.0

(\$ per unit)

EBITDA ⁽¹⁾	3.03	3.12	2.88
EBITDA before unrealized gains on risk management ⁽¹⁾	3.01	3.12	2.88
Net income	1.90	2.06	1.67
Net income per diluted unit	1.89	2.06	1.67
Net income before tax-adjusted unrealized gains on risk management ⁽¹⁾	1.90	2.06	1.67
Net income before tax ⁽¹⁾	2.00	2.04	1.65
Distributions declared ^{(2) (3)}	2.065	1.995	1.85
Cash flows			
Cash from operations	3.19	2.65	2.08
Funds from operations ⁽¹⁾	2.84	2.91	2.39
Units outstanding (millions)			
Weighted average number of units outstanding for the period (basic)	57.4	55.5	54.0
Weighted average number of units outstanding for the period (diluted)	57.4	55.5	54.1
End of period	58.1	56.4	54.6

⁽¹⁾ Non-GAAP financial measure. See discussion in the Non-GAAP Financial Measures section of this MD&A.

⁽²⁾ Distributions declared of \$0.175 per unit per month commencing in August 2007. From August 2006 to July 2007 distributions of \$0.17 per unit per month were declared. From March 2006 to July 2006 distributions of \$0.165 per unit per month were declared. From August 2005 to February 2006 distributions of \$0.16 per unit per month were declared. From January 2005 to July 2005 distributions of \$0.15 per unit per month were declared.

⁽³⁾ Excludes share distribution of AltaGas Utility Group Inc. shares in September 2007 providing an additional non-cash distribution of \$0.076 per unit. Excludes share distribution as a result of the spin-out of the Natural Gas Distribution (NGD) segment in November 2005, providing an additional non-cash distribution of \$0.54 per unit.

2007 Consolidated Financial Review

Net income in 2007 was \$108.8 million compared to \$114.5 million in 2006. Excluding the SIFT tax of \$5.4 million recorded in 2007, the \$6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in fourth quarter 2007, and the non-cash tax benefit of \$6.6 million due to tax rate reductions recorded in 2006, net income for the year ended December 31, 2007 was in line with 2006. Adjusting for these one-time tax items, net income was \$108.1 million in 2007 compared to \$107.9 million in 2006. Net income increased mainly due to higher power prices received on hedged

sales and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher extraction volumes exposed to frac spreads, higher frac spreads, a one-time gain from the sale of oil and gas production assets and lower interest expense. These increases were offset by lower revenues from unhedged sales due to lower Alberta spot power prices, lower throughput in the FG&P segment, the expiration of the Genesee power contract, higher operating and administrative costs, lower earnings in the Energy Services segment and a one-time charge related to non-recoverable costs incurred on a development project.

Consolidated net revenue for 2007 was \$324.0 million compared to \$318.9 million in 2006. The increase was due to higher hedge prices and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher frac spread-exposed volumes and higher frac spreads, and a one-time gain on the sale of oil and natural gas production assets. The increases were partially offset by the expiration of the Genesee power contract, lower throughput in the FG&P segment, a lower contribution from the oil and gas assets sold in May 2007 and decreased earnings in the Energy Services segment.

Operating and administrative expense for 2007 was \$150.3 million compared to \$145.8 million in 2006. The increase was due to additional costs related to new facilities, higher compensation and administrative costs and a one-time charge related to non-recoverable costs incurred on a development project.

Amortization expense for 2007 was \$47.1 million compared to \$46.4 million in 2006. The increase was primarily due to new and expanded facilities in the FG&P segment, partially offset by the sale of oil and natural gas production assets and the one-time write down of \$0.6 million of goodwill on a non-core investment in 2006.

Interest expense in 2007 was \$11.9 million compared to \$13.3 million in 2006. The decrease was primarily due to a lower average debt balance of \$234.9 million compared to \$274.1 million in 2006, partially offset by slightly higher borrowing rates. The average borrowing rate in 2007 was 5.3 percent compared to 4.9 percent in 2006.

Income tax expense for 2007 was \$5.9 million compared to an income tax recovery of \$1.1 million in 2006. The increase was mainly due to the non-cash charge of \$5.4 million to record future income tax liabilities for differences between the accounting and tax basis of AltaGas' assets and liabilities as a result of the SIFT tax, the \$6.6 million non-cash tax benefit recorded in 2006 due to Alberta and federal income tax rate reductions and a \$1.6 million tax impact on unrealized gains related to risk management assets and liabilities. These increases were partially offset by the difference between the \$6.1 million non-cash tax benefit due to the federal rate reductions enacted in late 2007 and the future income tax recovery of \$0.6 million from the sale of oil and natural gas production assets.

2008 Consolidated Outlook

With the addition of the new assets to AltaGas' current energy infrastructure and services business, AltaGas expects to deliver a significant increase in earnings and cash flow in 2008. The majority of the acquired assets will be included in the Extraction and Transmission (E&T) segment. AltaGas expects the proportion of its operating income from this segment to increase from 25 percent of overall operating income from all business segments in 2007 to approximately 40 percent in 2008.

In 2008 AltaGas expects operating income to increase as a result of the contribution of the new assets from the Taylor acquisition, higher hedge prices for power and continued strong frac spreads. The current forward curve for Alberta spot power prices is in the low to mid-\$70/MWh range, higher than the average Alberta Pool price for 2007. NGL volumes produced are expected to double year-over-year resulting in NGL volumes exposed to frac spreads increasing from approximately 9 percent of total volumes in 2007 to 12 percent in 2008. The current forward curve for frac spread is in the low to mid-\$20/Bbl range.

2006 Consolidated Financial Review

This section provides an overview of AltaGas' financial performance based on the audited annual Consolidated Financial Statements included in the 2006 Annual Report. All references to per unit amounts pertain to basic units outstanding for the period. Certain prior-year figures have been reclassified to conform to the current year's presentation.

Net income in 2006 was \$114.5 million (\$2.06 per unit) compared to \$90.3 million (\$1.67 per unit) in 2005. The increase was due to higher power prices received on both hedged and unhedged power volumes, lower power transmission costs, higher NGL frac spreads, higher extraction volumes and lower interest expense, partially offset by higher operating and administrative expense and higher income taxes.

In addition the Trust recorded a \$6.6 million non-cash future income tax benefit in 2006 as a result of a reduction in federal and Alberta corporate income tax rates. Net income in 2005 included one-time contributions of \$7.5 million related to the Trust's ownership of Taylor units, a full-year contribution from the Genesee power contract and the contribution from the Natural Gas Distribution (NGD) segment which was spun out on November 17, 2005.

Net revenue for 2006 was \$ 318.9 million compared to \$296.9 million in 2005. The increase was mainly due to higher prices received on the sale of power and lower power transmission costs (\$42.2 million), new facilities, higher processing fees and higher operating cost recoveries in the FG&P segment (\$15.1 million), higher NGL frac spreads and higher volumes processed in the extraction business (\$7.0 million), higher equity earnings in the Corporate segment (\$3.0 million), the acquisition of the assets and liabilities of iQ2 Power Corporation (iQ2) in late 2005 (\$2.2 million) and \$2.1 million higher net revenue from the gas-fired peaking plants. The increases in net revenue were partially offset by the spin-out of the NGD business in November 2005 (\$29.0 million), lower throughput in the FG&P segment (\$5.2 million), the expiration of the Genesee power contract in March 2006 (\$2.5 million) and \$1.6 million lower contribution from the oil and gas properties. In 2005 net revenue included one-time contributions of \$8.6 million related to the Trust's ownership of Taylor units.

Operating and administrative expense for 2006 was \$145.8 million, compared to \$141.4 million in 2005. The increase was due to higher administrative and compensation costs, additional costs from new FG&P facilities and the acquisition of iQ2. The increases were partially offset by the spin out of the NGD segment which reported operating and administrative costs of \$16.0 million in 2005. Increased third-party costs of approximately \$1.0 million were incurred in 2006 over 2005 to meet new certification requirements for reporting issuers mandated by the Canadian Securities Administrators.

Amortization expense for 2006 was \$46.4 million compared to \$47.4 million last year. The decrease was due to the spin out of the NGD segment which reported \$6.8 million in amortization expense in 2005, partially offset by increases related to the growth in capital assets resulting from acquisitions and internal expansion projects, higher depletion expense related to the Trust's oil and gas properties and higher amortization related to energy services contracts and relationships. In 2006 AltaGas also recorded a goodwill impairment of \$0.6 million related to a non-core investment.

Interest expense in 2006 was \$13.3 million compared to \$19.1 million in 2005. The decrease was due to lower average debt balances (2006 – \$274.1 million, 2005 – \$326.1 million) as a result of \$85.4 million in debt repayment in late 2005 using the proceeds from the spin-out of the NGD segment and due to higher funds from operations. Also contributing to the lower interest expense was a lower average borrowing rate of 4.9 percent in 2006, compared to 5.6 percent in 2005, mainly due to the August 2005 refinancing of term debt at lower rates.

Income tax recoveries for 2006 were \$1.1 million compared to recoveries of \$1.3 million in 2005. Income tax recoveries decreased as a result of higher net income before tax in 2006, partially offset by a non-cash future tax benefit of \$6.6 million that resulted from federal and Alberta income tax reductions in 2006. Income taxes reported in 2005 also included an expense of \$1.1 million related to the NGD segment, an adjustment of future tax balances that resulted in a recovery of \$1.6 million and a lower effective tax rate in respect of the Taylor capital gain reported in 2005.

Capital Outlook

AltaGas' strategy is to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. In order to execute its strategy, AltaGas expects capital expenditures to be approximately \$125 million and \$250 million in 2008 and 2009 respectively and to be split approximately 60 percent gas and 40 percent power in both years. Included in the estimated expenditures is approximately \$50 million annually for gas infrastructure projects. This estimate is based on projects that are in various stages of development and historical levels of expenditures in the FG&P segment. The estimate does not include the cost of developing the four potential run-of-river projects described below.

Bear Mountain Wind Park

AltaGas currently owns 100 percent interest of the BMWLP and the Bear Mountain Wind Park. AltaGas intends to finance the project, which is expected to cost approximately \$190 million, through its credit facilities and by including one or more third-party investors in the project, which would reduce AltaGas' ownership in the wind park to approximately 45 percent. The Bear Mountain Wind Park will have a capacity of approximately

100 MW and is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas entered into an EPC agreement with Enercon to supply and install wind turbines. AltaGas has also entered into a long-term service agreement with Enercon to operate and maintain the wind turbines. AltaGas commenced construction activities in December 2007 and intends to have the project completed by November 2009. Expenditures for 100 percent of the project are expected to be approximately \$55 million in 2008 and \$120 million in 2009. AltaGas has hedged approximately 21 percent of the total euros required for the project.

Sarnia Airport Storage Pool Project

AltaGas owns a 50 percent interest in the Sarnia storage project, with the other 50 percent being owned by Market Hub Partners Canada L.P., a Spectra Energy Corp. partnership. The project is expected to provide more than 5 Bcf of working capacity and deliverability of approximately 52 Mmc/d and will include three new wells, a compressor plant and approximately 18 kilometres of pipeline. The project is in the early stages of development, is subject to various regulatory and environmental approvals and is expected to be in full operation by mid-2009. AltaGas' share of the project is expected to cost approximately \$25 million.

Log Creek and Kookipi Creek Hydroelectric Projects

AltaGas is developing two hydroelectric facilities to be located on the Fraser River near Hope, British Columbia. The Log Creek and Kookipi Creek projects are each 10-MW run-of-river hydroelectric facilities in the final stages of permitting and licensing. Both facilities have 40-year electricity purchase agreements with BC Hydro. The plants are expected to be in operation in 2010 and to cost a total of approximately \$60 million to \$70 million.

Run-of-River Hydroelectric Plants Under Development

In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the ability to develop approximately 50 MW of hydroelectric power generation in British Columbia. The four new projects are at various stages of development, with the 14 MW Rainy River project near Gibson, British Columbia in an advanced development stage. Rainy River is expected to be operational in 2010. AltaGas anticipates the power from its hydro projects will be sold to B.C. Hydro through its Clean Power Call process. All of the development projects are subject to various regulatory and environmental approvals.

Harmattan Co-Streaming Project

The proposed Harmattan Co-streaming Project is expected to bring natural gas from TransCanada's Alberta system to the Harmattan Complex for processing to recover ethane, propane, butane and condensate. The Harmattan Co-streaming Project hearing at the Alberta Energy Resources Conservation Board (ERCB) is pending the outcome of the inquiry into the NGL extraction convention (the Inquiry). The Inquiry is anticipated to be completed by the fall of 2008. Upon approval, construction of the co-streaming project will commence, requiring approximately 12 months to complete. The project, as currently envisioned, is expected to cost in the range of \$70 million to \$90 million.

TAYLOR NGL LIMITED PARTNERSHIP 2007 RESULTS

AltaGas acquired all outstanding units of Taylor it did not already own effective January 10, 2008. The results described below are intended to provide the reader with a brief description of Taylor's 2007 results of operations to allow the reader to determine the potential impact of the Taylor acquisition on the results of the Trust.

In 2007 Taylor recorded a net loss of \$42.1 million compared to net income of \$28.7 million in 2006. Adjusting for the SIFT tax of \$69.1 million, the impact of mark-to-market accounting for financial instruments loss of \$5.9 million and gain of \$0.8 million in 2007 and 2006 respectively and compensation costs of approximately \$1 million related to the offer by AltaGas to acquire the units of Taylor, net income in 2007 was \$33.9 million compared to \$27.9 million in 2006.

Taylor recorded net revenue of \$109.9 million in 2007 compared to \$101.9 million in 2006. NGL sales averaged 21,126 Bbls/d in 2007 compared to 20,465 Bbls/d in 2006, up 3 percent and setting a new annual record. Gas volumes processed were 443 Mmc/d in 2007, compared to 452 Mmc/d in 2006.

Operating and administrative expense in 2007 was \$51.2 million compared to \$48.1 million in 2006. Included in 2007 was approximately \$1 million in higher compensation costs related to the offer by AltaGas to acquire the units of Taylor.

In 2007 Taylor's EBITDA was \$59.6 million compared to \$53.8 million in 2006, excluding the impact of mark-to-market gains and losses on financial instruments and one-time compensation costs related to the offer by AltaGas to acquire the units of Taylor.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other funds or entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures by AltaGas.

Net Revenue (\$ millions)	2007	2006	2005
Net revenue	324.0	318.9	296.9
Add: Cost of sales	1,104.4	1,043.7	1,205.4
Revenue (GAAP financial measure)	1,428.4	1,362.6	1,502.3

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of natural gas and power affect both revenue and cost of sales.

Operating Income (\$ millions)	2007	2006	2005
Operating income	126.6	126.7	108.1
Add (deduct): Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

Operating Income Before Unrealized Gains on Risk Management (\$ millions)	2007	2006	2005
Operating income before unrealized gains on risk management	125.5	126.7	108.1
Add (deduct): Unrealized gains on risk management	1.1	—	—
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Operating income before unrealized gains on risk management is a measure of the Trust's profitability from its principal business activities prior to accounting for how these activities are financed, how the results are taxed, and how the impact of gains from risk management activities affected operations. Operating income before unrealized gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses and amortization of capital assets.

EBITDA (\$ millions)	2007	2006	2005
EBITDA	173.7	173.1	155.5
Add (deduct): Amortization and goodwill impairment	(47.1)	(46.4)	(47.4)
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to how these activities are financed, how assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

**EBITDA Before Unrealized Gains
on Risk Management (\$ millions)**

	2007	2006	2005
EBITDA before unrealized gains on risk management	172.6	173.1	155.5
Add (deduct): Unrealized gains on risk management	1.1	-	-
Amortization and goodwill impairment	(47.1)	(46.4)	(47.4)
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

EBITDA before unrealized gains on risk management is a measure of the Trust's operating profitability. EBITDA before unrealized gains on risk management provides an indication of the results generated by the Trust's principal business activities prior to accounting for the impact of unrealized gains from risk management activities and how business activities are financed, how assets are amortized or how the results are taxed. EBITDA before gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses.

**Net Income Before Tax-Adjusted Unrealized
Gains on Risk Management (\$ millions)**

	2007	2006	2005
Net income before tax-adjusted unrealized gains on risk management	109.3	114.5	90.3
Add (deduct): Unrealized gains on risk management	1.1	-	-
Income tax expense on risk management	(1.6)	-	-
Net income (GAAP financial measure)	108.8	114.5	90.3

Net income before tax-adjusted unrealized gains on risk management is a better reflection of performance than net income as changes related to risk management are based on estimates related to commodity prices and foreign exchange rates over time. Net income before tax-adjusted unrealized gains on risk management is calculated from the Consolidated Statement of Income and Accumulated Earnings and is defined as net income plus unrealized gains on risk management and less income tax expense.

Net Income Before Tax (\$ millions)

	2007	2006	2005
Net income before tax	114.7	113.4	89.0
Add (deduct): Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Net income before tax is a better reflection of performance because it is not dependent on how those results are taxed which can change from year-to-year. Net income before tax is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income less income tax expense.

non-gaap financial measures

Funds From Operations (\$ millions)	2007	2006	2005
Funds from operations	162.9	161.7	129.0
Add (deduct): Net change in non-cash working capital and asset retirement obligations settled	20.4	(14.8)	(16.7)
Cash from operations (GAAP financial measure)	183.3	146.9	112.3

Funds from operations is used to assist management and investors in analyzing operating performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash flow from operations or other cash flow measures calculated in accordance with Canadian GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement costs.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income (\$ millions)	2007	2006
Field Gathering and Processing	18.2	25.4
Extraction and Transmission	39.1	35.2
Power Generation	94.6	90.9
Energy Services	2.0	2.8
Corporate	(27.3)	(27.6)
	126.6	126.7
Operating income before unrealized gain on risk management	125.5	126.7

FIELD GATHERING AND PROCESSING

The FG&P segment consists of 77 gathering and processing facilities in 30 operating areas in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets.

This segment includes the RET complex which is comprised of three interconnected processing facilities and related gathering systems that were acquired effective January 10, 2008 through Taylor. Subsequent to the Taylor transaction, AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, including 359 Mmcf/d of sour gas capacity. AltaGas operates 74 of its 77 facilities.

77
facilities in 3 provinces
within the WCSB.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmcf/d, which distinguishes it from most of its competitors in western Canada.

The FG&P segment's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	135.1	139.1
Net revenue	127.4	129.7
Operating and administrative expense	83.3	80.1
Amortization expense	25.9	23.6
Goodwill impairment	-	0.6
Operating income	18.2	25.4

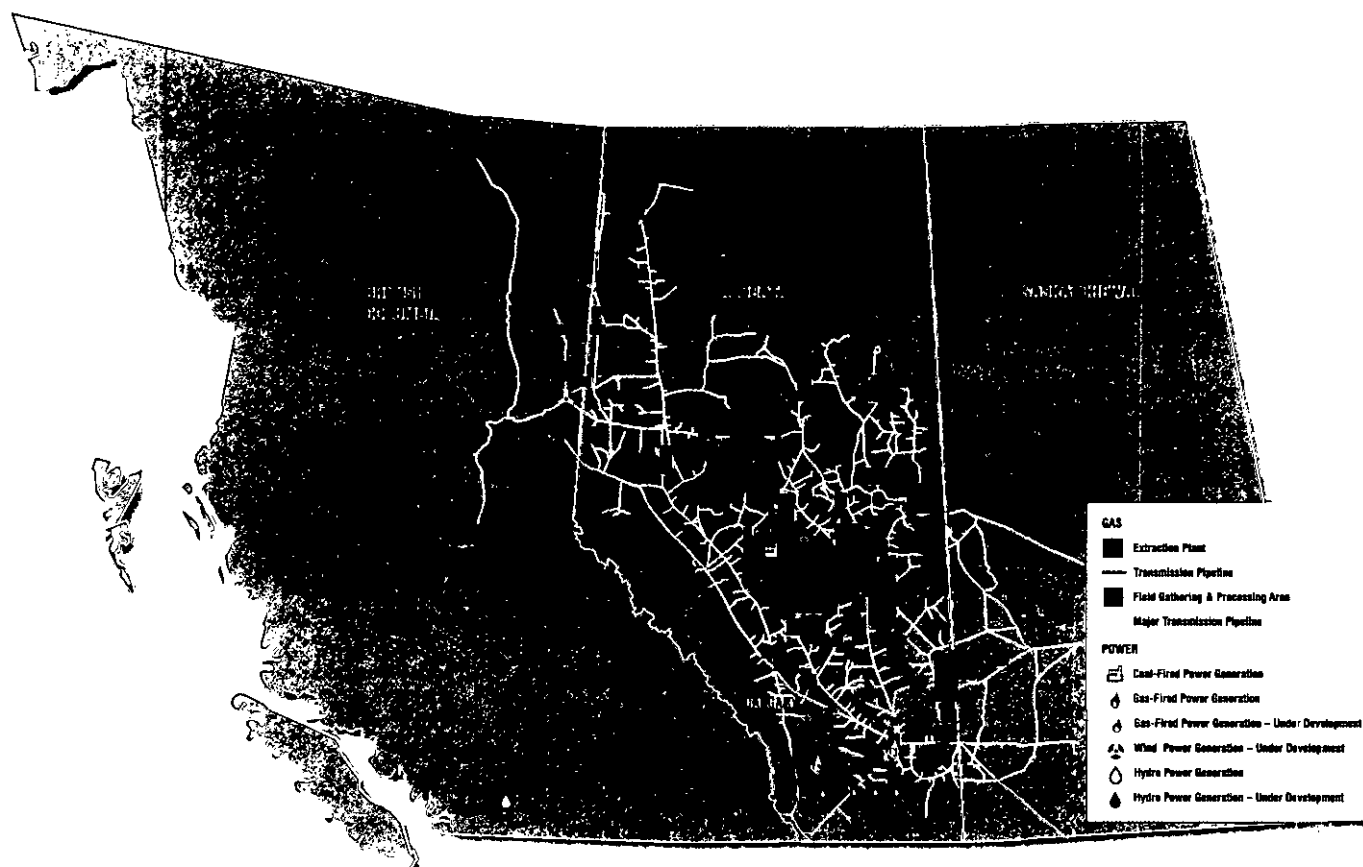
Operating Statistics	2007	2006
Capacity (Mmc/d) ⁽¹⁾	1,023	1,021
Throughput (gross Mmc/d) ⁽²⁾	511	549
Throughput (gross annual Mmc/d) ⁽²⁾	527	555
Capacity utilization (percent) ⁽³⁾	52	54
Average working interest (percent) ⁽¹⁾	91	92

⁽¹⁾ As at December 31.

⁽²⁾ Fourth quarter average.

⁽³⁾ Average for the period.

AltaGas Field Gathering and Processing Assets



As at March 3, 2008.

field gathering and processing

In the FG&P segment, operating income was \$18.2 million in 2007 compared to \$25.4 million in 2006. The decrease was due to lower throughput (\$7.6 million), lower equalization and minimum volume adjustments (\$3.1 million), higher general and administrative costs (\$1.0 million) and higher amortization due to expansions (\$0.6 million). The decreases were partially offset by the contribution from new plants (\$2.7 million) and higher rates and other revenues of \$2.4 million.

Capacity increased due to the addition of the new Acme and Corbett Creek facilities, which were partially offset by the sale of the Ikhil Joint Venture and the redeployment of the Del Bonita assets. Throughput in 2007 averaged 527 Mmc/d compared to 555 Mmc/d in 2006. The 5 percent decrease was primarily due to natural declines and lower producer activity, partially offset by new facility throughput additions of 11 Mmc/d from AltaGas' new Clear Prairie, Clear Hills, Princess and Acme facilities. Of the 28 Mmc/d throughput decrease, 16 Mmc/d was attributable to the North district and the balance to the South district. In the North district, the Wabasca area experienced throughput declines of 9 Mmc/d as a result of a less successful drilling program than the previous year. The decline in the South district was due to lower producer activity, partially offset by higher throughput from new wells at South Foothills. Utilization in 2007 was 52 percent compared to 54 percent reported in 2006.

Net revenue in the FG&P segment in 2007 was \$127.4 million compared to \$129.7 million in 2006. New facilities contributed \$6.1 million to net revenue in 2007, and increased rates contributed \$1.5 million. These increases were offset by lower throughput which resulted in a \$7.6 million decline in net revenue and lower routine equalization adjustments of \$1.7 million.

Operating and administrative expense in the FG&P segment in 2007 was \$83.3 million compared to \$80.1 million in 2006. The increase was mainly attributable to new facilities, higher property taxes and higher compensation costs, partially offset by lower operating costs.

Amortization expense in the FG&P segment in 2007 was \$25.9 million compared to \$24.2 million in 2006. The increase was due to new and expanded facilities, partially offset by the sale of the interest in the Ikhil Joint Venture and the write-off of goodwill in fourth quarter 2006.

FG&P Outlook

With the purchase of Taylor completed in January 2008, FG&P will integrate the RET Complex into its FG&P operations. The RET Complex is composed of three interconnected natural gas processing facilities approximately 40 km north of Lethbridge. The RET Complex is capable of handling both sour and sweet natural gas and provides gathering and processing services to approximately 55 producers having approximately 1,200 producing wells. Throughput in the RET Complex averaged 57 Mmc/d in the fourth quarter of 2007.

FG&P expects to report higher results in 2008 than in 2007. The increase is due to the addition of the RET Complex, recontracting at higher rates, optimization of facilities and increased operating cost flowthrough. AltaGas expects throughput to increase in 2008 over 2007 primarily due to the addition of the RET facilities.

AltaGas is working with customers to optimize underutilized assets. The underutilized Sedgewick facility is expected to be connected to the fully utilized Killam and Iron Creek facilities to allow gas to be diverted to Sedgewick and allow increased combined processing for the three facilities. AltaGas expects to increase its gas gathering and processing infrastructure in 2008 through acquisition and development of new facilities as producers reallocate capital from processing to their core activity of exploration and production. Increased drilling activity and producer activity in CBM areas, northwest Alberta and northeast British Columbia is also expected to provide opportunities for expansions, acquisitions and development of gas gathering and processing infrastructure. AltaGas expects to spend approximately \$50 million to grow and optimize its gathering and processing infrastructure in 2008, including gathering systems, capacity expansions and enhancements to its sour gas processing facilities.

AltaGas has experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity has been impacted by lower profitability and uncertainty regarding the new Alberta royalty regime. In 2008 AltaGas expects producer activity to rebound since average operating costs have declined, natural gas prices remain above the lows of 2007 and the completion of the Alberta royalty review should bring greater certainty to the industry. As a result, AltaGas expects demand for gathering and processing facilities to increase, thereby mitigating the impact of natural declines.

Business Strategy and Opportunities

The FG&P segment provides safe and reliable gathering and processing and ancillary services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share, servicing Alberta's future CBM production and moving westward to capitalize on increased exploration and drilling activities. While the WCSB is considered to be a maturing basin, AltaGas remains confident in the long-term demand for natural gas, strong natural gas prices and improvements in exploration and drilling technology and hence the long-term viability of the WCSB.

AltaGas' strategy is to:

- Maximize the profitability of the current field gathering and processing infrastructure:
 - Increase revenues by converting contracts to flowthrough operating costs and market based fees;
 - Offer flexible contractual terms and equal access to all producers;
 - Enhance operational efficiencies through consolidation, plant upgrades and integration with other business segments;
 - Integrate operational support for the peaking power plants; and
 - Manage costs and improve reliability.
- Grow its field gathering and processing infrastructure:
 - Expand into areas of unconventional gas production such as CBM, shale gas, and tight gas, where dedicated infrastructure is required to meet processing needs;
 - Expand into areas of high producer activity where there is increasing demand for gas gathering and processing infrastructure such as northwest Alberta and northeast British Columbia;
 - Invest in moveable assets that can be easily and quickly redeployed to new locations, improving operational flexibility and profitability, and responding quickly to producer requirements;
 - Increase working interests to control operations, increase efficiency and reduce operating costs;
 - Acquire underutilized assets that offer upside through increased throughput in areas where production is expected to support the investment; and
 - Construct or acquire and connect complementary facilities to create large facility complexes to capture operating synergies.

There are many opportunities to allow AltaGas to execute its strategy in the FG&P segment to meet the existing and future gathering and processing needs of its customers. In addition to its network of approximately 6,500 km of gathering lines, substantial processing capacity, expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities, approximately 80 percent of the compression units are skid-mounted. This allows AltaGas to relocate units quickly and cost effectively to respond to the changing processing needs of its customers. At present, the majority of gathering and processing infrastructure in western Canada is owned by oil and natural gas producers with 15 to 20 percent of the volumes in the WCSB processed by independent gas processors, including 3 percent processed by AltaGas. AltaGas believes that its strong operating skills and moveable assets create opportunities to work with customers to provide field gathering and processing services in a cost-effective and efficient manner.

New area development comes in large part from the drilling programs of AltaGas' existing and expanding customer base. Reserves analysis indicates that there are significant opportunities to increase natural gas production, including unconventional reserves within the WCSB, many in areas where gathering and processing infrastructure is limited thus providing opportunities for new infrastructure investment.

AltaGas may also see increased opportunities to acquire or build gathering and processing infrastructure from or on half of producers wishing to redeploy capital on exploration and production activities rather than on non-core activities such as processing.

Existing field gathering and processing areas usually have adjoining or overlapping gathering and processing systems. As AltaGas has grown, opportunities to expand by tying in new wells and building or purchasing adjoining facilities and systems have increased.

AltaGas also enhances the value of its gathering and processing infrastructure by integrating with the other business segments. The resulting suite of integrated services such as natural gas transmission, NGL extraction and natural gas and NGL marketing enhances value for its customers and investors.

Risk Management

AltaGas' field gathering and processing facilities process or transport natural gas from the WCSB. Throughput at these facilities is dependent on a number of factors including the level of exploration and development within the WCSB, the long-term supply and demand dynamics for natural gas which impact the longer-term price of natural gas, and the regulatory environment for natural gas market participants. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas throughput and from rising operating costs. AltaGas manages its exposure to financial risk in the FG&P segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Volume declines in the WCSB	- Contract provisions such as take-or-pay, capital cost recovery, area of mutual interest, geographic franchise with economic out, length of term and type of service as well as underpinned capital commitments. - AltaGas owns extensive gathering systems and moveable processing plants and can quickly deploy assets in response to customers' drilling activity and volume variability. - Increase geographic and customer diversity to reduce exposure to any one customer or area of the WCSB. - Expand into areas with strong producer activity, new sources of supply (including unconventional) and limited or fully utilized processing facilities.	- New contracts in 2007 included take-or-pay provisions. - New facilities and expansions underpinned by take-or-pay contracts. \$2.5 million in take-or-pay shortfall revenue in 2007. 29 of 30 operating areas have area of mutual interest provisions. - Approximately 80 percent of compression units are skid-mounted. - Relocated six compressors to optimize horsepower and reduce expenses in Cold Lake area. - In response to producer activity, AltaGas relocated approximately 40 pieces of equipment in 2007. - Approximately 250 customers with no customer representing more than 6 percent of FG&P net revenue during 2007. - Top 10 customers represented 13 percent of consolidated net revenues in 2007. 77 natural gas processing facilities in 30 operating areas in three provinces within the WCSB. - Developed new Acme facility to process CBM. - Built Acme plant and acquired Corbett Creek plant and associated gas gathering systems. These facilities are dedicated to processing CBM gas. - Acquired three facilities in southern Alberta through the Taylor acquisition in an area not previously served by AltaGas.
Increasing operating costs	- Contractual provisions provide for recovery of actual operating costs. - Acquire large working interests and operate facilities in order to control and optimize operations, and maximize efficiencies, customer demand and throughput.	79 percent of contracts include CPI escalators. 39 percent of operating costs were recovered directly from customers in 2007. - Increased operating cost flowthrough contracts to recover 45 to 50 percent of operating costs in 2008. - Operating costs remained flat in 2007. - Average working interest of 91 percent. - Operate 74 of 77 FG&P facilities.
Natural gas price fluctuations	Toll-for-service structure independent of commodity prices; revenues are a function of volumes processed.	The majority of processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput.
Environmental and safety	AltaGas has strong safety and environmental management systems, which it continually strives to improve.	Princess and Turin gas plants continued acid gas injection, reducing carbon dioxide and sulphur dioxide emissions to virtually zero.
Government and regulatory changes	Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	- Active participation in industry committees and regulatory forums. - Increased activity by CBM producers due to the new Alberta royalty regime increasing demand for AltaGas processing facilities.

EXTRACTION AND TRANSMISSION

The Extraction and Transmission segment consists of interests in four ethane and NGL extraction plants, one fractionation facility, five natural gas transmission systems and one condensate pipeline. The Taylor acquisition in January 2008 added one wholly owned extraction plant and two NGL pipelines in Alberta, increased AltaGas' ownership in the Joffre plant from 50 percent to 100 percent and added interests in an extraction plant in British Columbia.

Extraction

AltaGas owns extraction plant processing capacity through its interest in two extraction plants at Empress, Alberta, an extraction plant at Joffre, Alberta and another in Edmonton, Alberta. Also included in the extraction business is AltaGas' Bantry field fractionation facility. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was

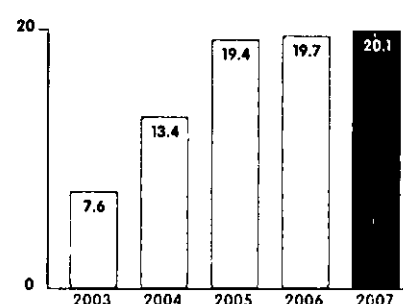
554 Mmcf/d at December 31, 2007. With the Taylor transaction effective January 10, 2008, AltaGas added the Harmattan Complex in Alberta, ownership interest in the Younger Extraction Plant in British Columbia and increased its ownership of the Joffre Extraction Plant in Alberta to 100 percent. The Harmattan Complex has natural gas licensed inlet capacity of 490 Mmcf/d, a deep cut NGL extraction unit, NGL fractionation net capacity of 25,000 Bbls/d and NGL terminal facilities. The Younger Extraction Plant, with NGL extraction ownership of 56.7 percent, has net processing capacity of 425 Mmcf/d and NGL fractionation and terminal ownership of 100 percent with net capacity of 25,000 Bbls/d. The increased ownership of the Joffre plant added net capacity of 125 Mmcf/d and terminalling with net capacity of 5,200 Bbls/d. AltaGas operates the Edmonton Ethane Extraction Plant, the Joffre Extraction Plant, the Bantry field facility and the Younger Extraction Plant.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted, they are sold as natural gas for their heating value at the prevailing natural gas price. As ethane and NGLs, the components are sold at higher prices that reflect the premium value for each of the individual commodities. In most cases the NGLs recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGLs to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGLs are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. NGLs, predominantly ethane, are feedstock for ethylene production.

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements.

Ownership
in 6 of the 10
Canadian extraction facilities.

Extraction Production
Bbls/d



Transmission

AltaGas owns five natural gas transmission systems and one condensate pipeline. Effective with the Taylor acquisition on January 10, 2008 the transmission business includes the Ethylene Delivery System (EDS) and the Joffre Feedstock Pipeline (JFP). The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The Suffield System in southeastern Alberta accounted for 72 percent of transmission net revenue in 2007 and has capacity of 400 Mmcf/d. The majority of the Suffield System's capacity is currently contracted by EnCana through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter.

Contractual volume commitments are expected to increase annually from approximately 370,000 GJ/d in 2007 to approximately 406,000 GJ/d in 2010 and will decline thereafter.

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis. The Porcupine Hills pipeline in southwest Alberta is a single-shipper condensate pipeline. The Summerdale and Battle Lake pipelines transport natural gas in central Alberta.

Results of Operations

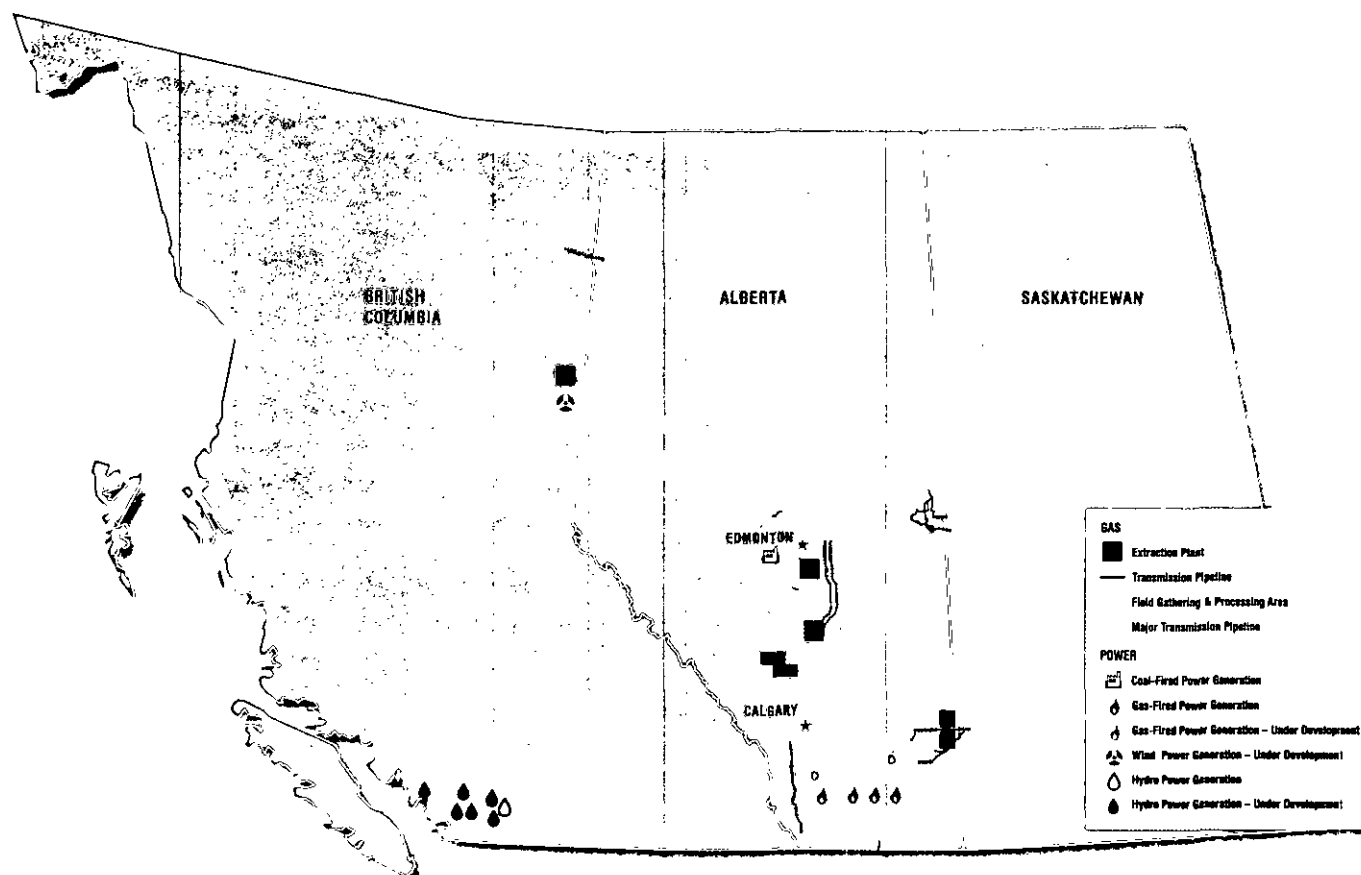
Financial Results (\$ millions)	2007	2006
Revenue	142.9	149.1
Net revenue	67.4	63.2
Operating and administrative expense	20.3	20.3
Amortization expense	8.0	7.7
Operating income	39.1	35.2
Operating Statistics	2007	2006
Extraction inlet capacity (Mmcf/d) ⁽¹⁾	554	554
Extraction volumes (Bbls/d) ⁽²⁾	20,108	19,696
Transmission volumes (Mmcf/d) ^{(2) (3)}	407	400
Frac spread (\$/Bbl) ^{(2) (4)}	\$ 21.38	\$ 18.47

⁽¹⁾ As at December 31.

⁽²⁾ Average for the period.

⁽³⁾ Excludes condensate pipeline volumes.

⁽⁴⁾ AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.



As at March 3, 2008.

Operating income in the E&T segment in 2007 was \$39.1 million, up from \$35.2 million in 2006. The increase was primarily due to higher frac spreads and higher frac spread-exposed NGL volumes in the extraction business and the expansion of the Cold Lake transmission system.

In 2007, average ethane and NGL volumes increased primarily as a result of the increased ownership at one of the extraction plants and higher utilization. Transmission volumes also increased slightly to 407 Mmcf/d from 400 Mmcf/d primarily due to higher deliveries on the Suffield transmission system.

Net revenue was \$67.4 million in 2007, compared to \$63.2 million in 2006. The increase was primarily due to higher frac spreads (\$1.4 million), higher extraction volumes (\$1.8 million), the expansion of the Cold Lake transmission system and higher committed volumes on the Suffield system.

Operating and administrative expense in the E&T segment in 2007 was \$20.3 million for 2007 and 2006. Lower costs due to lower volumes processed through the Edmonton Extraction Plant were offset by the increased costs at one of the Empress facilities due to the increased ownership.

Amortization expense in 2007 was \$8.0 million compared to \$7.7 million in 2006. The increase was due to the increased ownership at one of the Empress facilities and the enhanced ethane recovery project at the Edmonton extraction plant.

E&T Outlook

Results in the E&T segment are expected to increase materially in 2008. The acquisition of Taylor has added approximately 1 Bcf/d of inlet processing capacity, 23,500 Bbls/d of NGL production and 140,000 Bbls/d of NGL transportation capacity. Operating income in the E&T segment as a percentage of total operating income from all business segments is expected to increase from 25 percent in 2007 to approximately 40 percent in 2008. Volumes are also expected to increase as a result of opportunities to optimize and upgrade the infrastructure and consolidate extraction facilities in AltaGas' operating areas resulting in increased utilization and hence earnings.

Approximately 90 percent of the revenue from the E&T segment is based on long-term fee-for-service, cost-of-service and minimum volume commitment long-term contracts. The segment is expected to continue to deliver strong performance and predictable and stable returns. Commercial arrangements are structured to manage exposure to commodity price movements such that the majority of the volumes have downside protection to volatility and the remaining volumes allow AltaGas to participate in upside opportunity. These remaining volumes are driven by frac spreads which are expected to remain above recent historical levels. NGL prices continue to track the crude oil price which is expected to stay strong through 2008 while natural gas prices are expected to remain relatively flat resulting in continued strong frac spreads. Approximately 12 percent of extraction volumes are exposed to frac spread and approximately 45 percent of those volumes have been hedged at approximately \$21/Bbl for 2008. The remaining volumes remain exposed to frac spread. The current forward curve for frac spread is in the low to mid-\$20/Bbl range.

In second quarter 2008 a 23-day maintenance turnaround is planned at one of the facilities and is expected to cost approximately \$4.0 million in direct costs and lost operating income. In third quarter 2008 there are planned turnarounds for a total of 48 days at three facilities which are expected to cost approximately \$1.8 million in direct costs and lost operating income.

AltaGas has been an active participant in the Inquiry to ensure its existing and future extraction business is not negatively impacted. Proposed changes to the existing NGL extraction convention have been analyzed and mitigation strategies formulated. AltaGas believes that with the strategies in place, the outcome of the Inquiry will have no material impact on the extraction business.

On March 8, 2007, the Government of Alberta introduced legislation to reduce greenhouse gas emissions. The Climate Change and Emissions Management Amendment Act, along with its accompanying Specified Gas Emitters Regulation (SGER), state that facilities that emit more than 100,000 tonnes of greenhouse gases per year must reduce their emissions intensity by 12 percent per annum starting July 1, 2007. The Harmattan Complex falls within the scope of the legislation as its greenhouse emissions are slightly above 100,000 tonnes per year. Management's initial calculations for emissions intensity for 2007 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty.

In the transmission business, the full year of the Cold Lake expansion is expected to increase results compared to 2007 and AltaGas expects to pursue expansions similar to the Cold Lake Expansion, which may further enhance returns in the segment. An arrangement to utilize an unused portion of the Ethylene Delivery System has been completed and is also expected to result in higher results in 2008.

Business Strategy and Opportunities

The E&T segment provides safe and reliable processing and transportation services to its customers. The strategic focus is on optimizing current infrastructure and increasing throughput and market share to improve profitability through long-term fixed-fee or cost-of-service contracts. The main business driver in the extraction business is the volume of ethane and NGLs produced which is directly correlated to the volume of natural gas processed, natural gas composition, recovery efficiency of the extraction plant, plant on-line time, contractual arrangements and commodity price.

The E&T segment's business strategy is to:

- Maximize the profitability of the existing extraction and transmission infrastructure:
 - Increase throughput and utilization of existing extraction and transmission infrastructure;
 - Recontract for services to increase returns;
 - Execute commercial arrangements that have long-term fixed-fee or cost-of-service components;
 - Use frac spread hedges to lock-in margins and reduce exposure to frac spread volatility;
 - Operate plants to mitigate downside risk when frac spreads are low;
 - Lever existing assets and services to capture accretive growth; and
 - Offer marketing, transportation management and processing services in cooperation with the Energy Services and FG&P segments.
- Grow its extraction and transmission infrastructure:
 - Acquire and develop new facilities; and
 - Increase working interest ownership of partially owned plants.

There are many opportunities to enable AltaGas to execute its strategies in the E&T segment. Extraction growth opportunities may arise from plant modifications to increase product recoveries at facilities in which AltaGas already has ownership, by increasing interests in existing extraction plants, through construction of new facilities and by increasing throughput through additional extraction agreements. Extraction plant opportunities typically reflect a long-term, cost-of-service ethane processing arrangement contracted with Alberta ethylene producers, long-term NGL fixed processing fee arrangements and a small percentage of short-term sales of NGLs based on an Edmonton or U.S. index.

The natural gas supply to the Joffre and Edmonton extraction plants depends on natural gas demand pull from central Alberta's petrochemical industry, residential and other commercial usage. The economy in the area remains strong, resulting in sustained volumes of gas processed at these plants. The Empress extraction plants rely on the supply of natural gas from natural gas export volumes, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. Growth in NGL production at Younger will depend on the ability to increase natural gas volumes processed at the plant. The Harmattan Complex is a significant service provider in its capture area. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Streaming Project is also expected to increase processing capability to the plant. Overall, the diverse nature of its extraction infrastructure should allow AltaGas to increase throughput, utilization and profitability.

The extraction business is also strongly influenced by frac spreads. As frac spreads are at historically high levels and are expected to remain high into the foreseeable future, AltaGas expects to show strong results from this business.

The transmission business' main value drivers are the fees earned, which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market. Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is limited or non-existent. In capturing opportunities, AltaGas focuses on long-term, cost-of-service type contractual arrangements. Increased activity in heavy oil in the Cold Lake area is expected to provide AltaGas with additional opportunities to expand its Cold Lake system in a similar fashion to the expansion completed in 2007. Drilling activity in areas served by AltaGas' other transmission assets is also expected to provide opportunities to expand infrastructure and increase utilization of the assets.

Risk Management

AltaGas' extraction facilities and transmission assets process or transport natural gas, NGLs and condensate from the WCSB. Utilization of these facilities is dependent on a number of factors including natural gas supply, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the longer-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for NGL market participants. The extraction business is further influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. AltaGas manages its exposure to financial risk in the E&T segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term decline in throughput and gas composition variability	- Contract provisions underpin capital commitments. - Long-term contracts independent of throughput. - Collaborate with Energy Services segment to increase volumes through the extraction facilities. - Expand existing facilities or acquire or construct new facilities.	- Majority of contracts are multi-year. - In 2007 75 percent of NGL production under long-term, fixed-fee arrangements. - Ethane production sold under long-term, cost-of-service or fixed-fee contracts. - Utilization at Empress facilities above 98 percent in 2007 despite a 23-day shutdown in May. 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed-fee. - Expanded the Cold Lake natural gas transmission system. - Completed the Taylor acquisition and added Harmattan Complex, the Younger Plant, the remaining ownership in Joffre Extraction Plant, and two NGL pipelines.
Commodity price fluctuations	- Contracting terms and processing fees independent of commodity prices with fee-for-service or cost-of-service provisions. - Hedging practice to reduce exposure to frac spread volatility and lock-in margins when the opportunity arises to increase profitability.	- NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. - Less than 9 percent of total extraction production was exposed to frac spreads in 2007. - Ethane production sold under long-term, cost-of-service or fixed-fee contracts. 75 percent of NGL production under long-term, fixed-fee arrangements. - The transmission business is not directly affected by commodity price fluctuations. - Hedged 45 percent of volumes exposed to frac spread for 2008.
Increasing operating costs	- Acquire large working interests to control and optimize operations and maximize efficiencies. - Structure fees to recover actual operating costs.	- Significant portions of cost-of-service contracts provide for operating cost recovery. - Some extraction contracts allow recovery of certain operating costs, including shrinkage gas attributable to that production. - Operator of all transmission assets and four of six extraction facilities. - Maintenance management programs ensure tight cost controls and equipment reliability.
Environmental and safety	AltaGas has strong safety and environmental management systems, which it continually strives to improve.	Maintained its Certification of Recognition from Alberta Human Resources and Employment.
Government and regulatory changes	Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	Active participation in industry committees and regulatory forums.

POWER GENERATION

AltaGas has 353 MW of coal-fired base-load capacity through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired peaking capacity. The Trust also has a 25 percent interest in a 7 MW run-of-river hydroelectric generation facility in British Columbia as a result of the Taylor acquisition. AltaGas' 378 MW of installed power capacity served approximately 5 percent of Alberta's power demand in 2007. In 2007 AltaGas also purchased 14.4 MW of gas-fired peaking capacity which is currently being installed at two FG&P locations in Alberta. The Power Generation segment is primarily engaged in the sale of electricity and ancillary services to the Alberta wholesale market.

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output. The 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to a specified target level of 86 percent of the Sundance B plants' rated capacity and to ancillary services until December 31, 2020.

175 MW
of renewable generation
under development.

Results in the Power Generation segment are largely driven by generator availability, hedge prices (for the portion of capacity that is hedged) and Alberta spot prices (for the portion of capacity that is not hedged). The relationship among production, spot prices and cost of sales is specified in the PPAs. Generally, AltaGas is compensated when power production is less than target levels, at a rate based on the previous 30-day average spot price (RAPP). Similarly, if generation from the PPAs is above target, AltaGas is obligated to provide the owner of the generation facility, TransAlta Corporation (TransAlta), financial compensation based on the difference between actual availability and target availability, multiplied by the RAPP. The financial exposure may be positive or negative depending on the difference between the current Alberta spot price and RAPP. The majority of the cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Alberta Power Pool trading charges. The price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation, rather than the prevailing market price for coal.

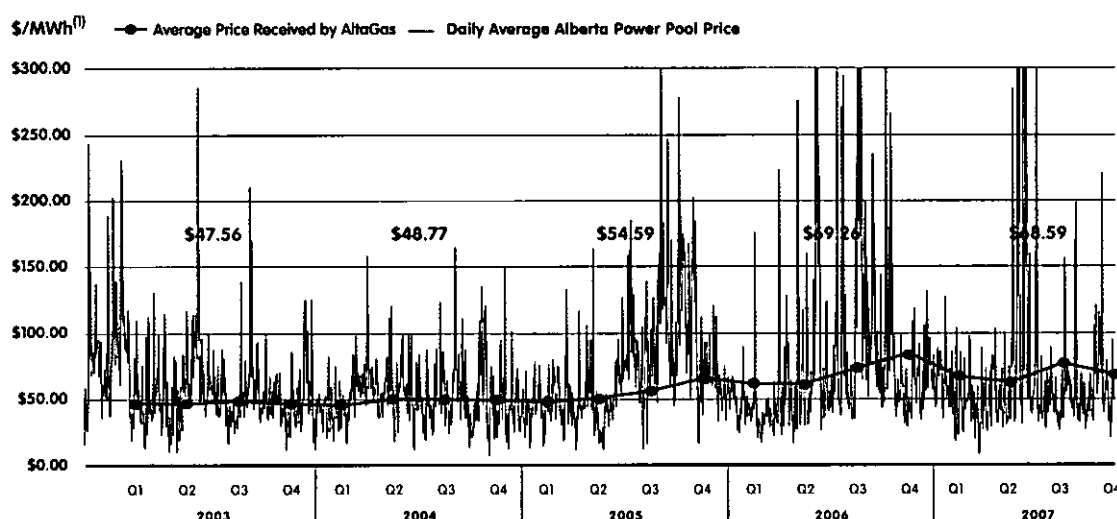
AltaGas also leases, operates and maintains 25 MW of gas fired generation. The lease began in September 2004 and includes an option at the end of the initial term of 10 years to renew for a further 15 years or to purchase the assets. The Energy Services segment manages the gas requirement and the units are dispatched from the Edmonton extraction plant. This 25 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' power business and provides partial backstopping to outages at Sundance. In addition, due to their quick ramp up capability, the peaking plants provide revenue from the sale of energy and ancillary services. Construction is underway for an additional 14.4MW of gas-fired peaking capacity at the Bantry and Parkland gas processing facilities. Upon connection to the electricity grid, the new gas-fired peaking plants will increase the Trust's peaking capacity by 58 percent and further increase operational flexibility and backstopping to the Sundance B PPAs.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	182.5	199.4
Net revenue	104.2	99.6
Operating and administrative expense	2.1	1.3
Amortization expense	7.5	7.4
Operating income	94.6	90.9

Operating Statistics	2007	2006
Volume of power sold (GWh)	2,661	2,878
Price received on the sale of power (\$/MWh) ⁽¹⁾	68.59	69.26
Alberta Power Pool average spot price (\$/MWh) ⁽¹⁾	66.84	80.48

⁽¹⁾ Average for the period.



⁽¹⁾ Chart truncated at \$300.00; daily average Alberta power pool price reached as high as \$999.99/MWh.

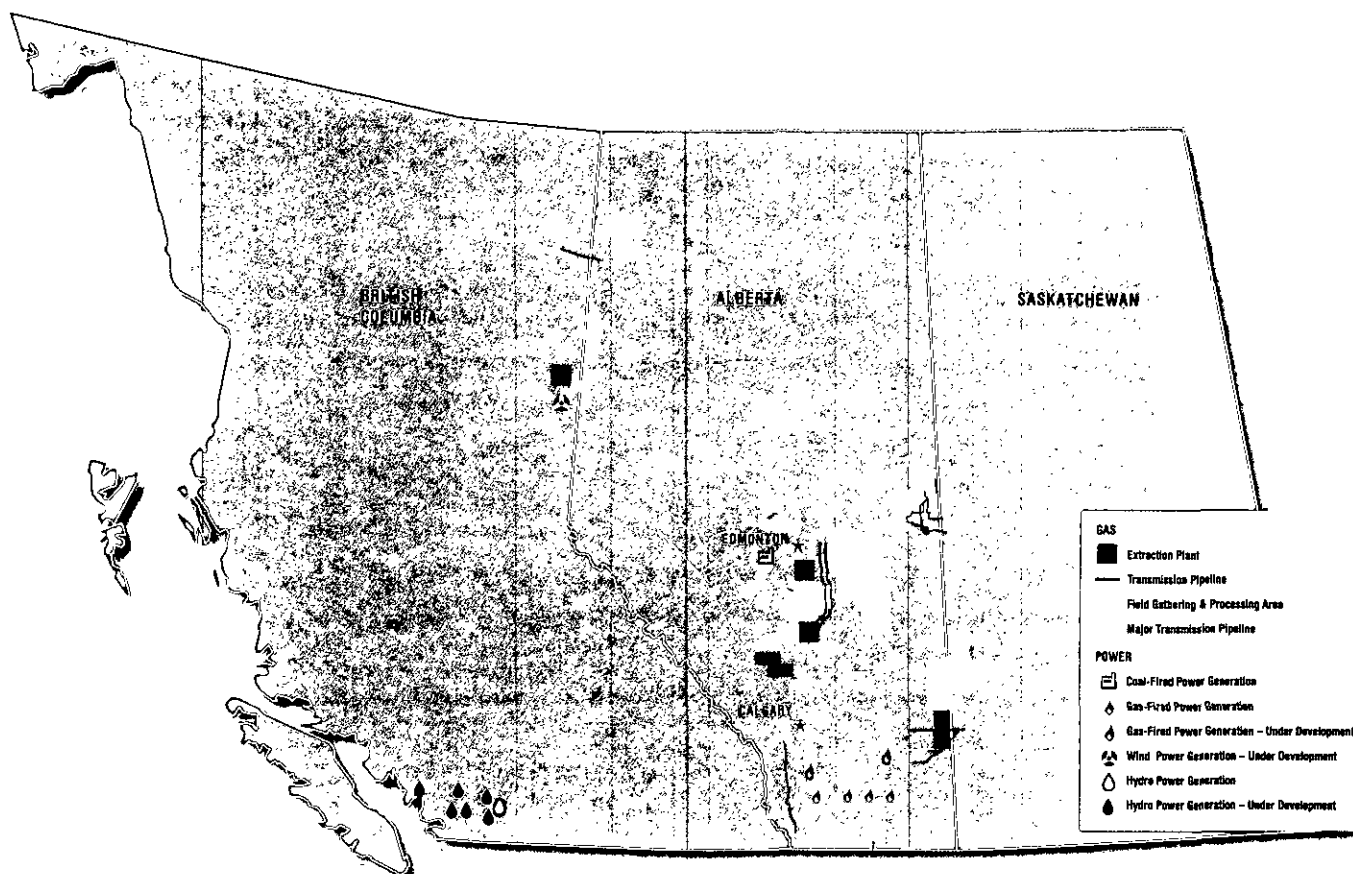
Operating income in the Power Generation segment was \$94.6 million for 2007 compared to \$90.9 million for 2006. The increase was due to higher power prices received on hedged sales, lower PPA costs and lower transmission costs. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices, the expiration of the Genesee contract and costs incurred to comply with Alberta's SGER.

The volume of power sold in 2007 was lower than in 2006 primarily as a result of the Genesee contract expiration on March 31, 2006.

Net revenue was \$104.2 million for 2007 compared to \$99.6 million for 2006. The increase included \$34.6 million due to higher hedge prices, \$9.4 million due to lower PPA costs mainly as a result of a favourable 30-day RAPP during the Sundance B planned outage and lower transmission costs of \$3.2 million. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices (\$35.8 million), the expiration of the Genesee contract (\$4.1 million), \$2.0 million of costs incurred to comply with Alberta's SGER and approximately \$0.5 million in other fixed and variable costs.

Operating and administrative expense of \$2.1 million in 2007 was higher than the \$1.3 million reported in 2006, primarily due to the operating and maintenance services AltaGas began providing to the leased peaking plants in March 2007.

Amortization expense of \$7.5 million in 2007 was similar to \$7.4 million in 2006.



As at March 3, 2008.

power generation

Power Generation Outlook

Operating income in the Power Generation segment is expected to be higher in 2008 than in 2007. The contribution from hedged power volumes is expected to be higher than in 2007 as a result of average hedge prices of approximately \$76/MWh in 2008 compared to \$66/MWh in 2007. Consistent with AltaGas' hedge program, approximately two-thirds of the power available from the Sundance B PPAs has been hedged and the remaining is exposed to the spot price of power in Alberta. In early 2008, the forward market for power prices indicates that power prices will remain relatively strong, in the low to mid-\$70/MWh range until 2012. PPA costs are expected to be higher in 2008 due to higher power generated. However, as the price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation rather than the prevailing market price of coal, it is not expected to have a significant impact on PPA costs in 2008.

On June 27, 2007 the Alberta government passed the SGER which requires large final emitters to reduce greenhouse gas emissions intensity by 12 percent per year beginning July 1, 2007, to purchase an equivalent amount of offset credits from intra-Alberta sources, or to pay \$15/tonne of emissions over the 12 percent reduction into a provincially administered technology fund. This regulation affects the Sundance facility and is expected to increase 2008 operating expense by approximately \$5 million. To the extent these costs can be recovered through higher power pool prices, by the physical reduction of emissions intensity, or by creating or acquiring offsets, the impact of these costs would be mitigated.

The 14.4 MW of new gas-fired peaking capacity will be integrated into ongoing operations and is expected to be operational in second quarter 2008. Installation of the generating capacity is estimated to cost approximately \$10 million and is expected to be accretive to net income and cash flow once operational.

Revenue from the gas-fired peaking facilities is derived from the sale of energy and ancillary services. Based on the expected spot price for power and natural gas in Alberta for 2008, AltaGas expects the utilization of its gas-fired peaking facilities to average 20 percent. The plants also provide ancillary services, which generate revenue without delivering power to the grid.

Business Strategy and Opportunities

The Power Generation segment consists primarily of AltaGas' 50 percent ownership of the Sundance B PPAs, which are contractual arrangements entitling the Trust to the output from the 353 MW coal-fired base-load Sundance B plant. The Trust's current hedging strategy and its gas-fired peaking plants optimize financial and operating risk related to the PPAs. The Trust's strategy is to maximize the profitability of the existing power assets and to grow its power generation infrastructure and operational capability.

AltaGas' Power Generation strategy is to:

- Maximize the profitability of the existing power assets:
 - Evaluate, modify and refine the power hedge strategies as appropriate to increase earnings stability and growth from the Sundance PPAs;
 - Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy and ancillary services;
 - Identify and execute opportunities to create value from the regulation of greenhouse gas emissions; and
 - Capitalize on internal synergies and integration efforts with other operating segments.
- Grow its power infrastructure:
 - Acquire and develop power infrastructure supported by strong power supply and demand fundamentals;
 - Acquire and develop power generation projects supported by long-term power sales arrangements;
 - Diversify power generation portfolio by geography and fuel source;
 - Develop operating capability in other fuel sources;
 - Capitalize on increasing demand for clean power by investing in renewable and clean power project development across Canada and the northern U.S.; and
 - Invest in power opportunities such as additional PPAs in Alberta and other jurisdictions.

The supply-demand fundamentals supporting the Power Generation segment remain favourable in North America. AltaGas expects this will continue to support strong power prices especially in Alberta where the Trust is most exposed to power prices. This could increase the profitability of AltaGas' power generation assets allowing AltaGas to earn higher revenues from the sale of power and ancillary services. The expectation of continued strong power prices is supported by the tightening of the electricity reserve margin in Alberta, as transmission constraints are delaying the addition of new generation facilities. In December 2007, the Alberta Electric System Operator (AESO) published a report titled "Future Demand and Energy Outlook, 2007-2027" which projected provincial demand growing at an average annual rate of 3.2 percent over the next five years. Given the demand and supply forecasts, AltaGas expects reserve margins to remain at less than 10 percent until 2011 at which time it is expected to increase to about 15 percent. In early 2008 the forward curve for power prices indicates that prices will remain relatively strong, in the low to mid-\$70/MWh range until 2012. As at December 31, 2007, 93 percent of AltaGas' generation capacity was low-cost base-load coal-fired generation, resulting in strong future earnings in this market environment.

Power generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, in Alberta, may present additional growth opportunities through the development and ownership of new capacity. In 2006 AltaGas forged relationships with power generation developers to pursue its strategy to grow its renewable energy portfolio. In 2007 the Trust acquired 100 percent of the BMWLP which owns the Bear Mountain Wind Park under construction near Dawson Creek, British Columbia. In July 2007 the GEDLP owned 50 percent by AltaGas, responded to Manitoba Hydro's 300 MW Wind Request for Proposal (RFP). While the partners were not successful in this RFP, GEDLP may bid the projects into future RFPs.

The Power Generation segment is poised for growth with the Bear Mountain Wind Park under construction and expected to be in service in November 2009. At present AltaGas owns 100 percent of the Bear Mountain Wind Park and intends to include one or more third-party investors in the project, which would reduce ownership in the wind park to approximately 45 percent. AltaGas also has several run-of-river hydroelectric projects, including two 10-MW plants with 40-year energy purchase arrangements with BC Hydro, which are currently in the permitting and licensing phase and expected to be in service in 2010. In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric power generation in British Columbia. GEDLP has also developed a portfolio of power projects in Canada and the United States that the Trust believes will fuel further growth in its power infrastructure.

Risk Management

The main risks faced in the power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risk related to the deregulation of power and environmental legislation. Power results are generally driven by volumes of power generated, power prices and the cost of power. Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates, and reductions in power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	- A disciplined hedging strategy – hedge targets approved by the Board of Directors. - Hedge transactions monitored by the Risk Management Committee. - In-depth Alberta power market knowledge and experience. - Hedge own electrical demand requirements. - Own and operate gas-fired peaking capacity which backstops the Sundance PPAs and sells energy and ancillary services in volatile markets.	- Financial hedge contracts generally have terms ranging from three to 36 months. - Average sales price received in 2007 was \$68.59/MWh, compared to average monthly Pool price that ranged from a low of \$48.37/MWh in May to a high of \$155.73/MWh in July. - Supply 11 MW for own use and supply approximately 40 MW to Alberta power retail customers. - Peaking plants contributed \$4.3 million to net revenue in 2007 through sales of ancillary services and energy.
Volume of power generation	- PPAs set specified target availability levels. TransAlta is obligated to provide AltaGas financial compensation to the specified target availability level which was 86 percent of rated capacity in 2007. This is accomplished by a financial payment based on the difference between actual availability and target availability, multiplied by the 30-day RAPP. - Diversification of fuel sources and geography. - Hedging strategy balances price and operating risk. - Pursue further diversification through development partnerships and acquisitions. - Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	- Minor impact on revenue during 2007 planned outage. 25 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. 14.4 MW additional peaking capacity under construction. - Short-term power purchase contracts used to mitigate the impact of 2007 planned outage. - Wind and hydro power projects under development outside Alberta. - Strong operating history at Sundance B with no significant loss as a result of a force majeure event.
Cost of power	- Cost of power from the coal-fired generation based on PPA indices. - Cost of power is not exposed to market price of coal.	Modest decrease in cost of power from Sundance PPAs in 2007.
Counterparty risk	- Strong credit policies in place. - Counterparty credit reviews continually updated. - Credit thresholds established using conservative credit metrics. - Exposures and impact of price shocks on liquidity closely monitored.	- All financial hedge counterparties are investment-grade. - No counterparty defaults in 2007.
Construction risk	- Major Projects group manages and monitors significant construction projects. - Use EPC contracts where appropriate to manage construction cost risk. - Effective procurement policies and procedures and vendor selection.	Executed EPC with Enercon for delivery and installation of the Bear Mountain Wind Park turbines.
Lack of community support	AltaGas has active corporate and regulatory affairs departments.	Held several events to inform and educate the communities in which AltaGas is developing projects.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Regulatory risk	The PPAs have provisions for financial relief in the event that policies and regulations render them uneconomic.	AltaGas personnel hold influential positions on key industry policy and oversight committees.
Environment and safety risk	- AltaGas has strong safety and environmental management systems which are continuously being monitored for improvements. - Focus on mitigating the impact of the SGER.	- Bantry and Parkland peaking plants will use compressed natural gas to drive the peaking plant starter motors. The compressed gas will then be captured and cycled through the peaking plants rather than vented into the environment. - Potentially capture offsets from existing AltaGas operating facilities. - Possible offset through higher Alberta Power Pool prices.

ENERGY SERVICES

The Energy Services segment consists of two main components: an energy management business providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users; and a gas services business which supports the operations of the FG&P, E&T and Power Generation segments and buys and resells natural gas, transportation and storage. This segment also included a small portfolio of oil and natural gas production assets that were sold in May 2007.

Energy Management

The energy management business consists of providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users. As of January 1, 2007 AltaGas' energy management services are provided under the brand name "ECNG Energy" and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Burnaby, British Columbia.

Adding value
to our infrastructure business.

The majority of the energy management fee-for-service revenues is based on one-to-three-year evergreen contracts, with some extending as far as eight years. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives. The energy management business also manages electricity supplies for AltaGas' internal power demand in the FG&P and E&T segments and sells power to industrial and commercial end-users, thereby providing a longer-term market for hedging power sales.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-user customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

One of the key functions of the Energy Services segment is to support AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas transmission pipelines and provides gas control services to balance gas flows. Gas services markets gas for FG&P customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' gas-fired power peaking plants.

In addition to supporting other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions and managing potential credit exposures. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into the eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has been successful in achieving positive margins while providing improved netbacks for producers.

Over the past several years, AltaGas had accumulated a portfolio of oil and natural gas production assets in connection with larger acquisitions of gathering and processing facilities. These oil and natural gas assets were sold in the second quarter of 2007.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	1,022.5	948.9
Net revenue	20.9	24.7
Operating and administrative expense	15.6	17.1
Amortization expense	3.3	4.8
Operating income	2.0	2.8
Operating Statistics	2007	2006
Energy management service contracts ⁽¹⁾	1,466	1,394
Average wholesale volumes marketed (GJ/d) ⁽²⁾	388,217	327,057

⁽¹⁾ Active energy management service contracts at the end of the reporting period.

⁽²⁾ Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Operating income in the Energy Services segment was \$2.0 million in 2007 compared to \$2.8 million in 2006. The decrease was due to non-recurring earnings reported in the energy management business in 2006, higher gas costs to supply a natural gas contract, higher operating and administrative expense and lower contributions from the operations of the oil and natural gas production assets which were sold effective May 31, 2007. These decreases were partially offset by an increased fixed-price commodity and transportation net revenue in the gas services business, growth in both gas and electricity in the energy management business and the one-time pre-tax gain from the sale of the oil and natural gas production assets.

Net revenue was \$20.9 million in 2007 compared to \$24.7 million in 2006. The decrease included a \$4.0 million lower contribution due to lower volumes and prices related to the operation of the oil and gas production assets, \$2.5 million related to non-recurring earnings in the energy management business, and \$1.4 million due to higher gas costs to supply a natural gas contract. These decreases were partially offset by \$2.0 million from higher optimization, transportation, fixed-price and balancing gas margins in the gas services business, the one-time pre-tax gain from the sale of oil and natural gas production assets of \$1.5 million and \$0.5 million from growth in the energy management business.

Operating and administrative expense was \$15.6 million in 2007 compared to \$17.1 million in 2006. The decrease was primarily due to lower costs related to the operation of the oil and natural gas production assets (\$2.0 million), partially offset by \$0.5 million in higher administrative expenses.

Amortization expense in 2007 was \$3.3 million compared to \$4.8 million in 2006. The decrease was primarily due to the sale of the oil and natural gas production assets of \$1.7 million, partially offset by higher amortization of \$0.2 million related to the addition of new information systems to support the business.

Energy Services Outlook

The increased gas infrastructure acquired through the Taylor transaction is expected to provide additional opportunities for the Energy Services business to identify and execute on opportunities to enhance the earnings from these assets. To the extent that the Energy Services segment can do so, this may increase earnings in the segment or contribute to increased earnings in the other operating segments.

The core businesses within the Energy Services segment are the advisory fee-based business servicing non-residential gas and electricity end-users (energy management), and the fixed-margin gas marketing business (gas services). AltaGas expects results in the Energy Services segment in 2008 to be slightly lower than 2007 results, excluding the gain on sale of the oil and gas production assets in 2007. Lower revenues from fixed-price gas sales are anticipated due to the low natural gas price environment. However, the recent acquisition of Taylor will provide the gas services business with an increased geographic footprint and assets to increase its integration opportunities to enhance unitholder value.

The Energy Services segment is an important element in increasing the value of assets in AltaGas' other segments. Energy Services works with the other segments to optimize AltaGas' assets and in this capacity is expected to contribute to earnings growth across all segments.

Business Strategy and Opportunities

The Energy Services segment provides agency advisory services to energy end users in the commercial, institutional, small industrial and agricultural sectors and locks in margin through the buying and selling of natural gas, transportation and storage. The segment also provides value added services to the FG&P, E&T and Power Generation segments and their customers by capitalizing on its in depth knowledge of the energy markets to optimize AltaGas' infrastructure and enhance value.

AltaGas' Energy Services business strategy is to:

- Maximize profitability of its existing business:
 - Identify opportunities for increased synergies and value across AltaGas' infrastructure and services to increase profitability;
 - Create new service offerings and build on national brand development;
 - Increase market penetration of national energy management services in natural gas and electricity;
 - Manage credit and market risk within the risk tolerances established by the Board; and
 - Increase cost efficiency and improve competitive advantage through common processes and marketing efforts.
- Grow Energy Services infrastructure:
 - Add physical infrastructure such as gas storage capacity.

The key value driver in the Energy Services segment is the services provided to the other infrastructure based business segments. The Energy Services segment provides gas control and gas supply contracting services to the FG&P, E&T and Power Generation segments. AltaGas' strategy is to identify additional opportunities to enhance the value of its infrastructure through transactions and support services. This includes identifying opportunities to increase margins earned in transmission, maintain the cost-effective flow of gas through extraction plants and increase services provided to producers.

The Energy Services business provides AltaGas with a portfolio of contracts with locked-in margins over multiple years. These contracts result in stable and predictable earnings and cash flows. However, these transactions require credit support to backstop potential default risk with suppliers and customers. AltaGas allocates capital to this business based on the credit risk profile of the contracts in order to avoid excessive exposure to default risk. The Trust closely monitors the credit and market risk profile of the contracts through metrics such as value at risk and credit event liquidity analysis.

The Energy Services business incurs significant general and administrative (G&A) expenses as it employs high human capital. AltaGas is focused on operating margin as a percentage of G&A and strives to increase this metric through cost efficiencies from common processes, marketing efforts and promotional materials. Sharing of gas and electricity market knowledge across all regions and streamlining the operations to more effectively serve customers across Canada is also expected to result in improved margins.

In 2007 AltaGas announced its first infrastructure project in the Energy Services segment with the development of the Sarnia Airport Storage Pool project in Ontario. This is AltaGas' first investment in storage infrastructure and is expected to be in service in 2009. Access to a storage asset near the Dawn Hub in Ontario is expected to provide AltaGas with the ability to further capitalize on its in-depth knowledge of the eastern gas markets to further enhance unitholder value. Given the long-term supply and demand fundamentals of natural gas and the increasing impact of liquefied natural gas in the North American natural gas markets, storage capacity is expected to play a more strategic role in the buying, selling and transportation of gas. AltaGas expects to pursue further growth opportunities in storage infrastructure to further enhance margins in Energy Services.

Risk Management

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers. The most significant risks in the Energy Services segment are counterparty and commodity price risk. The credit-intensive nature of this business requires balance sheet support to transact fixed-price energy supply purchase and sale agreements.

While long-term fixed-margin contracts provide stable earnings and cash flow, the Trust employs a disciplined approach to credit allocation to mitigate the risk of counterparty default. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty default	• Strong credit policies in place. • Internal credit ratings and thresholds established. • Exposures and impact of price shocks on liquidity are closely monitored. • Diverse customer and supplier base. • Business model in energy management is based on agency arrangements where counterparty credit risk for commodity exists between the supplier and the end-user.	• Majority of counterparties are investment-grade. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2007. • In 2007 AltaGas added customers in key sectors nationwide. • Purchase natural gas from a wide array of investment-grade suppliers.
Commodity price fluctuation	• Commodity Risk Policy prohibits transactions for speculative purposes. • Strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems and natural gas markets. • Strong customer relationships.	• All gas service transactions are back-to-back with locked-in margins. • Energy management contracts have terms from one to eight years with locked-in fees. • Advisory fee services business experienced renewal rate of 95 percent in 2007. • Market and manage FG&P customers' gas for a fee. • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk.

CORPORATE

The Corporate segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity, return on capital and operating income as a percentage of net revenue without the impact of the volatility in commodity prices and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity as risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate segment.

Financial Results (\$ millions)	2007	2006
Revenue ⁽¹⁾	5.1	4.4
Net revenue	6.2	4.4
Operating and administrative expense	31.2	29.7
Amortization expense	2.3	2.3
Operating loss	(27.3)	(27.6)
Operating loss before unrealized gains on risk management	(28.4)	(27.6)

(1) Excludes unrealized gains (losses) on risk management.

The operating loss before unrealized gains on risk management was \$28.4 million in 2007 compared to \$27.6 million in 2006. The increased loss was due to \$1.3 million in higher office, computer and compensation costs and \$1.9 million in write-offs related to costs incurred on development projects. These increases were partially offset by \$1.0 million in lower professional and consulting fees, \$0.8 million in higher general and administrative costs allocated to the operating segments and a one-time gain of \$0.4 million on the unwinding of interest rate swaps as a result of the issuance of \$100 million of medium-term notes in January 2007. Effective in second quarter 2007 AltaGas reduced its influence over Taylor and commenced accounting for its interest in Taylor using the cost method. The effect of the change in the accounting method on the operating loss in 2007 was negligible.

Net revenue was \$6.2 million in 2007 compared to \$4.4 million in 2006. The increase was due to the unrealized gain of \$1.1 million related to risk management contracts and back-to-back commodity purchases and sales as a result of the adoption of accounting standards effective January 1, 2007, that require the fair value of all financial instruments to be reflected on the financial statements. On adoption, AltaGas recorded financial statement related assets and liabilities of \$107.8 million and \$110.6 million respectively. The net impact to accumulated earnings and to Other Comprehensive Income on January 1, 2007 was \$0.2 million and \$2.6 million respectively. The increase was also due to the gain recorded as a result of unwinding interest rate swaps in first quarter 2007 of \$0.4 million and to \$0.3 million from higher interest and investment revenue.

Operating and administrative expense was \$31.2 million in 2007 compared to \$29.7 million in 2006. The increase was primarily related to \$1.9 million in a one-time charge related to the write-off of costs incurred on development projects and \$0.4 million in higher compensation costs, partially offset by lower professional and consulting fees of \$1.0 million and lower general corporate overhead.

Amortization expense for 2007 was consistent with 2006.

Corporate Outlook

The operating loss for 2008 is expected to be higher than in 2007 due primarily to the acquisition of Taylor and AltaGas growth through acquisitions and the expansion of current facilities. In 2007 Taylor recorded approximately \$8 million in corporate costs on a normalized basis. AltaGas has realized approximately \$2 million in cost savings of the total \$3.0 million identified at the time the Taylor transaction was announced. The segment's revenue will decrease as AltaGas will no longer be recording investment income from Taylor in the Corporate segment and also due to a decrease in ownership of Utility Group from 26.7 percent to 19.6 percent.

The effects of financial instruments are based on estimates relating to commodity prices and foreign exchange rates over time. The actual amounts will vary based on these drivers and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2007 AltaGas acquired \$86.1 million in capital assets, long-term investments and other assets, up from \$71.5 million in 2006. The increase was due to acquiring \$68.2 million in capital assets and \$17.9 million in long-term investments and other assets, of which \$20.3 million was an increase in the fair value of Taylor units which were reported as assets available for sale and \$3.4 million was for costs related to the acquisition of Taylor, partially offset by the special distribution of Utility Group common shares valued at \$4.2 million and the elimination of \$2.1 million in loans advanced to BMWLP. The \$46.4 million in disposals of capital assets included the \$30.2 million disposition of the original cost of the oil and natural gas production assets in Energy Services and the original cost of the \$14.4 million interest in the Ikhlil Joint Venture reported in the FG&P segment.

Maintenance capital expenditures totalled \$5.7 million in 2007 compared to \$6.1 million in 2006, of which \$4.0 million in 2007 was in the FG&P segment. Of the \$56.2 million spent on growth capital in 2007 (2006 – \$62.0 million), \$23.3 million was spent in the FG&P segment, which included \$16.5 million on CBM projects consisting of the Acme plant construction and the Corbett Creek acquisition, and another \$6.5 million spent on upgrading and expanding existing FG&P facilities. In the Power Generation segment, \$13.9 million was spent on the Bear Mountain Wind project and \$6.6 million was for the new peaking generation equipment and installation costs to date. AltaGas also invested \$8.0 million in the Sarnia Airport Storage Pool project in Ontario as part of its strategy to grow its gas infrastructure and diversify geographically. Costs of \$3.4 million were incurred related to the offer to purchase the outstanding Taylor units, which was more than offset by the \$4.2 million special distribution of Utility Group shares to AltaGas unitholders. Administrative capital expenditures of \$24.2 million in 2007 were significantly higher than the \$3.4 million reported in 2006, primarily due to a \$20.3 million increase in the fair value of Taylor units which were reported as assets available for sale.

For the year ended December 31, 2007 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	29.1	5.0	22.0	9.8	2.3	68.2
Long-term investments and other assets	–	–	(0.5)	–	18.4	17.9
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals						
Capital assets	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

For the year ended December 31, 2007 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	4.0	1.7	–	–	–	5.7
Growth	23.3	3.3	21.5	9.3	(1.2)	56.2
Administrative	1.8	–	–	0.5	21.9	24.2
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

invested capital

For the year ended December 31, 2006 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	58.5	4.3	–	0.8	2.2	65.8
Long-term investments and other assets	–	–	4.3	–	1.4	5.7
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals						
Capital assets	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

For the year ended December 31, 2006 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	5.0	0.8	–	0.3	–	6.1
Growth	53.3	3.4	4.3	0.2	0.8	62.0
Administrative	0.2	0.1	–	0.3	2.8	3.4
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates, particularly in the Power Generation segment and with respect to interest rates on debt. During 2007, the Trust had positions in the following types of derivatives:

Commodity Forward Contracts

The Trust executes gas, power, and other commodity forward contracts to manage its asset portfolio and lock in margin from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The Energy Services segment transacts primarily on this basis.

Commodity Swap Contracts

The Trust executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power Generation segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and whereas prices ranged from \$0.00/MWh to \$999.99/MWh in 2007, the average spot price was \$66.84/MWh for the year. AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio that management deemed optimal. The average price received for power by the Trust was \$68.59/MWh in 2007. The Trust opportunistically executes fixed-for-floating frac spread swaps to manage its NGL frac spreads.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating frac spread swaps to manage its NGL frac spreads. The E&T segment's results are affected by frac spreads. In the fourth quarter of 2007, the Trust entered into NGL frac spread agreements for 1,400 Bbls/d at \$25.50/Bbl for the first quarter 2008 and for 700 Bbls/d at \$21.50/Bbl from April 1 to December 31, 2008. With the acquisition of Taylor, AltaGas has assumed frac spread hedges for an additional 1,200 Bbls/d with an average price of \$20.00/Bbl for January 1 through December 31, 2008.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2007 the Trust had interest rate swaps with varying terms to maturity of \$25.0 million. Including AltaGas' MTNs and capital leases, the rate was fixed on 100 percent of AltaGas' debt.

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts where a fixed rate is locked in against a floating rate. The Trust's foreign exchange risk was not material at December 31, 2007. The Trust has entered into a number of forward rate contracts to hedge its euro exposure as it relates to the Bear Mountain project.

LIQUIDITY AND CAPITAL RESOURCES

AltaGas expects that funds from operations in 2008 will be sufficient to meet the Trust's distributions to unitholders and the majority of its budgeted maintenance and growth capital expenditures. The balance of its budgeted growth capital and a certain amount of unbudgeted acquisitions will be financed through the Distribution Reinvestment Plan (DRIP) and existing bank lines. Should larger acquisitions require financing beyond existing sources, management is confident, based on historical success, that equity and debt capital markets could be accessed to provide additional financing. At this time AltaGas does not reasonably expect any presently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash, except that cash from operations may be impacted by the taxable component of the Trust's distribution beginning in the 2011 taxation year.

On January 10, 2008 AltaGas acquired Taylor units for the aggregate purchase price of \$598.7 million, including cash of \$256.3 million and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all of the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$11.0 million in transaction costs which was funded with bankers' acceptances through AltaGas' syndicated credit facilities.

Cash Flows (\$ millions)	2007	2006
Cash from operations	183.3	146.9
Investing activities	(63.4)	(78.5)
Financing activities	(120.6)	(66.9)
	(0.7)	1.5

Cash from Operations

Cash from operating activities reported on the Consolidated Statements of Cash Flows increased by \$36.4 million, or 25 percent, to \$183.3 million in 2007 from \$146.9 million in 2006. The increase in cash flow was primarily due to a decrease in non-cash working capital items. Accounts receivable decreased as a result of lower volumes and commodity prices, the timing of payments in the Power Generation segment, and gas storage positions that had built up in the latter half of 2006 decreasing in 2007. The decrease in working capital was partially offset by lower payables as a result of lower commodity prices and the timing of payment of capital costs.

Working Capital (\$ millions except ratio amounts)	2007	2006
Current assets	305.4	263.4
Current liabilities	286.1	239.7
Working capital	19.3	23.7
Current ratio	1.07	1.10

Investing Activities

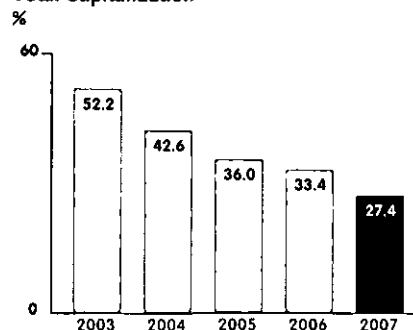
During 2007 the Trust used cash for investing activities of \$63.4 million compared to \$78.5 million in 2006. The decrease in cash used for investing activities was due to lower acquisitions of capital assets in 2007, increased customer deposits and higher proceeds on dispositions of non-core assets.

Financing Activities

Cash used for financing activities was \$120.6 million in 2007 compared to \$66.9 million used in 2006. Significant financing activities in 2007 included a reduction to debt of \$44.4 million, \$8.1 million higher distributions paid to unitholders than in 2006 and \$4.8 million lower proceeds from the DRIP as a result of the suspension of the Premium component of the DRIP.

Capital Resources

Debt as a Percent of Total Capitalization



The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2007 AltaGas had total debt outstanding of \$220.7 million, down from \$265.5 million as at December 31, 2006. As of December 31, 2007 the Trust had \$200.0 million in MTNs outstanding and had access to prime loans, bankers' acceptances and letters of credit through bank lines totaling \$425.0 million. As at December 31, 2007 the Trust had drawn bank debt of \$10.0 million and letters of credit outstanding of \$64.5 million.

All of the borrowing facilities have financial tests and other covenants customary for these types of facilities, which must be met at each quarter-end. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

AltaGas' target debt-to-total-capitalization ratio is 40 to 45 percent. The Trust's debt-to-total-capitalization ratio as at December 31, 2007 was 27.4 percent, down from 33.4 percent at December 31, 2006. The Trust's earnings interest coverage for the rolling 12 months ended December 31, 2007 was 10.65.

The Dominion Bond Rating Service (DBRS) rates AltaGas Income Trust and the MTNs issued by AltaGas Income Trust at BBB (low). In January 2008, DBRS confirmed AltaGas' medium-term notes and stability ratings at BBB (low) and STA-3 (middle) respectively. The trend on the medium-term notes rating was changed to Stable from Positive.

Standard & Poor's Ratings Services (S&P) rates the Trust's long-term corporate credit at BBB- with a stable outlook, and the senior unsecured debt at BBB-. In December 2007 S&P affirmed AltaGas' ratings.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity of an entity to meet its financial commitment in accordance with the terms of an obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an entity's distribution stream when compared to other stability rated entities.

Credit Facilities (\$ millions)	Borrowing capacity	Drawn at December 31, 2007	Drawn at December 31, 2006
Demand operating facility	50.0	2.8	–
Letter of credit facility	75.0	61.7	63.3
Syndicated operating credit facility ⁽¹⁾	300.0	10.0	154.3
	425.0	74.5	217.6

⁽¹⁾ Extendible revolving-term credit facility that can be extended beyond the current term date of September 30, 2010 for an additional year.

At December 31, 2007 the Trust held a \$75.0 million (2006 – \$75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to \$25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2007 the Trust had letters of credit of \$61.7 million (2006 – \$63.3 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of \$2.8 million (2006 – \$3.0 million) outstanding against the demand operating facility.

Contractual Obligations

(\$ millions)	Payments Due by Period				
	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt	211.7	4.7	207.0	–	–
Capital leases	12.5	1.9	3.8	3.8	3.0
Operating leases	15.9	3.9	6.8	5.2	–
Purchase commitments	150.2	34.4	115.8	–	–
Total contractual obligations	390.3	44.9	333.4	9.0	3.0

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2007 was \$10.0 million (2006 – \$11.8 million) with the balance due in monthly payments comprising principal and interest of \$0.2 million.

The Trust has long-term operating lease agreements for office space, office equipment and automotive equipment. The Trust also has purchase commitments for the development of the Bear Mountain Wind project including the purchase and installation of the wind turbines.

Other Commitments

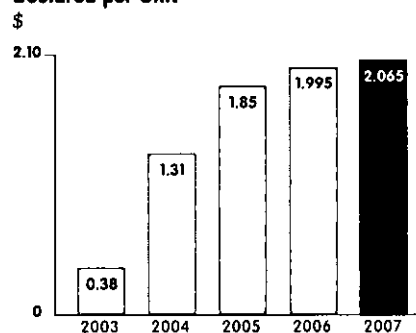
Under the terms of a 1997 long-term gas supply contract the Trust is committed to supplying natural gas at prices ranging from \$2.34/Mcf in 2007 to \$2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. One of those producers defaulted on its obligation under its gas supply contract in 1999, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

DISTRIBUTIONS

AltaGas' distributions are determined giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. AltaGas declared \$118.6 million of distributions to unitholders in 2007 compared to \$110.8 million in 2006.

The Trust suspended the Premium component of the DRIP (PDRIP) effective with the August 2007 distribution. The regular component of the DRIP remains in effect and will continue to support AltaGas' financing strategy. In the future, as conditions warrant, the Trust may consider reinstating the PDRIP based on AltaGas' capital requirements and desire to maintain an efficient capital structure. While the PDRIP is suspended, PDRIP participants will continue to receive regular cash distributions. For further information on the DRIP please visit AltaGas' website at www.altagas.ca.

Cash Dividends/Distributions Declared per Unit



The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, increased its monthly cash distribution to \$0.175 per unit (\$2.10 per unit annualized) from \$0.17 per unit (\$2.04 per unit annualized) payable on September 17, 2007 to unitholders of record on August 27, 2007. This was AltaGas' fourth distribution increase since converting to a trust in May 2004. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment date or record date falls on a weekend or holiday.

In addition, a special distribution of one Utility Group common share for every 100 trust units and exchangeable units of AltaGas held on August 27, 2007 was made on September 17, 2007. The Trust distributed 577,416 shares valued at \$4.2 million.

The following table summarizes AltaGas' distribution declaration history since 2005:

(\$ per unit)	2007	2006	2005
First quarter	\$ 0.510	\$ 0.485	\$ 0.45
Second quarter	0.510	0.495	0.45
Third quarter	0.520	0.505	0.47
Fourth quarter	0.525	0.510	0.48
Distribution of shares ⁽¹⁾	0.076	-	0.54
	\$ 2.141	\$ 1.995	\$ 2.39

⁽¹⁾ On September 17, 2007, one share of Utility Group was issued for every 100 trust and exchangeable units held on August 27, 2007. On November 17, 2005, one share of Utility Group was issued for every 13.9592 trust and exchangeable units held on November 14, 2005.

Assuming a unit was held throughout 2007, for income tax purposes the Trust expects 69.73 percent of the total distributions declared in 2007 to be taxed as property income, 0.22 percent as dividend income, 0.62 percent as capital gains and 29.43 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

TRUST UNIT INFORMATION

Under the terms of the restructuring of AltaGas into an income trust effective May 1, 2004, ASI security holders exchanged their shares in ASI for Trust units and eligible security holders also received exchangeable units that are exchangeable into Trust units on a one-for-one basis. The exchangeable units are not listed for trading on an exchange.

Units Outstanding

At January 31, 2008 the Trust had 63.4 million Trust units and 2.2 million exchangeable units outstanding and a market capitalization of \$1.5 billion based on a closing trading price on January 31, 2008 of \$23.35 per Trust unit. At January 31, 2008 there were 1.3 million options outstanding and 350,967 options exercisable under the terms of the unit option plan.

CHANGES IN ACCOUNTING POLICIES

2007 Changes

Effective January 1, 2007 AltaGas adopted the revised Canadian Institute of Chartered Accountants (CICA) Handbook Section 1506. This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements.

Financial Instruments

Effective January 1, 2007 the Trust prospectively adopted the CICA Handbook; Section 1530 "Comprehensive Income"; Section 3855 "Financial Instruments – Recognition and Measurement"; Section 3865 "Hedges"; and Section 3861 "Financial Instruments – Disclosure and Presentation". The impacts of adopting the new standards are reflected in the Trust's annual results, and prior year comparative financial statements have not been restated. While the new rules resulted in changes to how the Trust accounts for its financial instruments, there were no material impacts on the Trust's current financial results. For a description of the new accounting rules and the impact on the Trust's financial statements of adopting such rules, see note 12 to the annual Consolidated Financial Statements for the year ended December 31, 2007.

Future Accounting Changes

Section 1535 "Capital Disclosures"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

Section 3031 "Inventories"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

Section 3862 "Financial Instruments – Disclosures" and Section 3863 – "Financial Instruments – Presentation"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

International Financial Reporting Standards (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian generally accepted accounting principles with IFRS over an expected five-year transition period, with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions which have been made using careful judgment. AltaGas' significant accounting policies are contained in the Notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations and asset impairment assessment. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Costs

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs is a critical accounting estimate because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2025 and 2035), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guaranteed contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

RELATED PARTIES

The Trust sold \$83.4 million of natural gas to, and incurred transportation costs of \$0.5 million charged by Utility Group in 2007. The Trust also paid management fees of \$0.4 million to, and received management fees of \$29,000 from, Utility Group for administrative services in 2007. In addition, the Trust provided \$0.3 million of operating services to Utility Group.

During 2007 the Trust sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for \$9.0 million. The gain on the sale was negligible.

The Trust pays rent under a lease for office space to 2013761 Ontario Inc., which is owned by an employee. Payments of approximately \$85,000 were made in 2007 (2006 – \$80,000). The five-year lease expired in 2007 and was renewed for an additional year.

DISCLOSURE CONTROLS AND PROCEDURES

The Trust maintains disclosure controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under applicable laws is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

In accordance with Multilateral Instrument 52-109 (Certification of Disclosure in Issuers' Annual and Interim Filings), management carried out an evaluation, under the supervision and with the participation of management, including the Chairman and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that disclosure controls and procedures were effective as of December 31, 2007 to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized, and reported within the time periods specified in the Ontario Securities Commission's rules and forms.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining adequate internal controls over financial reporting. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be designed effectively can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Trust has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework to evaluate the design of internal controls over financial reporting.

At December 31, 2007 management assessed the design of the Trust's internal control over financial reporting and concluded that such internal control over financial reporting is suitably designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. The assessment also concluded that there were no material weaknesses in the design of AltaGas' internal control financial reporting that have been identified by management.

There have been no changes in design of internal control over financial reporting during the year ended December 31, 2007 that have materially affected or are reasonably likely to materially affect AltaGas' internal control over financial reporting.

SUBSEQUENT EVENTS

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7 MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders \$11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of \$245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, \$27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was \$598.7 million, including \$256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$11.0 million in transactions costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:

(\$ millions)

Cost of 8.9% investment in Taylor originally owned by AltaGas		24.6
Purchase price for the remaining 91.1% of Taylor Units		
Cash considerations	256.3	
Units	198.9	
Estimated transaction costs	11.0	
Equity portion of Taylor convertible debentures	2.1	468.3
Total consideration		\$ 492.9

Purchase price allocation for 100% of Taylor:

(\$ millions)

Assets acquired		
Current assets	30.8	
Capital assets	590.0	
Energy service arrangements, contracts and relationships	83.9	
Goodwill	108.2	
Long-term investments and other assets	4.6	817.5
Less Liabilities assumed		
Current liabilities	31.2	
Long-term debt	110.2	
Convertible debentures	22.2	
Asset retirement obligations	14.4	
Future income taxes	144.0	
Future employee obligations	2.5	
Risk management	0.1	324.6
		\$ 492.9

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income. As of January 10, 2008, Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of \$256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately \$610 million compared to \$220.7 million as at December 31, 2007 and a debt-to-total capitalization ratio of approximately 45 percent.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for \$4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at \$24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

FOURTH QUARTER HIGHLIGHTS

Net income for the three months ended December 31, 2007 was \$31.8 million (\$0.55 per unit) compared to \$27.3 million (\$0.49 per unit) for the same period in 2006. Excluding a \$6.1 million non-cash tax recovery due to reduced federal tax rates enacted in fourth quarter 2007, net income for fourth quarter 2007 was \$25.7 million. Net income increased primarily due to higher hedge prices and lower costs in the Power Generation segment, lower operating and administrative costs, higher frac spreads and higher extraction volumes exposed to frac spreads. These increases were more than offset by lower throughput and operating cost recoveries in FG&P, lower Alberta spot power prices and a lower contribution from the Energy Services segment.

On a consolidated basis, net revenue for the quarter ended December 31, 2007 was \$76.4 million compared to \$84.6 million in the same quarter of 2006. Net revenue decreased in fourth quarter 2007 due to lower Alberta spot power prices, lower throughput in FG&P, and lower revenues as a result of the sale of oil and gas production assets in May 2007. The decreases were partially offset by higher hedge prices and lower costs in the Power Generation segment, higher frac spreads and higher frac spread-exposed extraction volumes.

Operating and administrative expense for fourth quarter 2007 was \$36.2 million down from \$40.1 million in the same quarter of 2006. The decrease was primarily due to lower operating costs in FG&P, lower costs as a result of the sale of the Ikhlil Joint Venture and the oil and natural gas production assets, as well as lower consulting fees in part related to the compliance with securities regulations incurred in 2006. These decreases were partially offset by higher compensation and administrative costs.

Amortization expense for fourth quarter 2007 was \$11.4 million compared to \$12.5 million in the same quarter last year. The decrease was due to the disposition of oil and natural gas production assets in 2007 and a \$0.6 million write-down of goodwill on a non-core investment in fourth quarter 2006, partially offset by new and expanded FG&P facilities.

Interest expense for fourth quarter 2007 was \$2.9 million compared to \$3.3 million in the same quarter of 2006. The decrease was due to lower average debt balances of \$218.6 million compared to \$271.9 million for the same period in 2006, partially offset by higher average borrowing rates. The average borrowing rate in fourth quarter 2007 was 5.5 percent compared to 4.9 percent in fourth quarter 2006.

In fourth quarter 2007 the Trust reported an income tax recovery of \$5.8 million compared an income tax expense of \$1.4 million in the same quarter last year. Lower federal corporate income tax rates enacted in the quarter resulted in a tax recovery of \$6.1 million and was offset by higher tax expense of \$0.3 million due to higher income subject to tax.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2008 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per unit
Gathering and processing volumes ⁽¹⁾	5 Mmcf/d	0.016
Gathering and processing operating margin per Mcf ⁽¹⁾	1 cent /Mcf	0.027
Alberta electricity prices ^{(1) (2)}	\$1/MWh	0.010
Natural gas liquids fractionation spread ^{(1) (3)}	\$1 per Bbl	0.011
Interest rates ⁽¹⁾	25 bps	0.004

⁽¹⁾ Includes the effects of the Taylor assets added January 10, 2008.

⁽²⁾ Based on 70 percent of PPA volumes being hedged.

⁽³⁾ Based on 55 percent of exposed volumes not hedged.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENTLY COMPLETED QUARTERS

(\$ millions)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net revenue ⁽¹⁾	76.4	88.2	80.1	79.3	84.6	82.5	72.8	79.1
Operating income ⁽¹⁾	28.9	37.5	31.2	29.0	32.0	33.7	26.0	35.0
Net income	31.8	31.4	21.1	24.6	27.3	28.8	29.9	28.6
(\$ per unit)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net income	-	-	-	-	-	-	-	-
Basic	0.55	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Diluted	0.55	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Distributions declared ⁽²⁾	0.525	0.52	0.51	0.51	0.51	0.505	0.495	0.485

⁽¹⁾ Non-GAAP financial measure. See "Non-GAAP Financial Measures".

⁽²⁾ Excludes the special distribution issuance of one common share of Utility Group for every 100 trust and exchangeable units held on August 27, 2007, valued at \$0.076 per unit.

Identifiable trends in AltaGas' business in the past eight quarters reflect: the organization's internal growth; acquisitions; a favourable business environment including generally increasing power prices in Alberta; asset dispositions; and lower throughput in the FG&P segment.

Significant items that impacted individual quarterly earnings were as follows:

- Results in the FG&P segment are typically lower in the first quarter compared to the fourth quarter;
- In second quarter 2006 a \$6.6 million non-cash future income tax benefit was recorded as a result of a reduction in the federal and Alberta corporate income tax rates;
- In fourth quarter 2006 the Trust reported a \$0.6 million goodwill impairment and deferred \$0.8 million in revenue in the transmission business;
- In second quarter 2007 the Trust recorded a \$6.5 million future tax expense as a result of new tax legislation included in Bill C-52 which was substantially enacted by the Government of Canada. This non-cash charge to earnings relates to the temporary differences between the accounting and tax basis of AltaGas' assets and liabilities; and
- In fourth quarter 2007 a \$6.1 million non-cash future income tax benefit was recorded as a result of a reduction in the federal corporate income tax rates.

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. Further, management is satisfied that the financial information contained in this annual report is consistent with that presented in the Consolidated Financial Statements. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that its assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine

the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.



DAVID W. CORNHILL
CHAIRMAN AND CHIEF EXECUTIVE OFFICER OF
ALTAGAS GENERAL PARTNER INC., DELEGATE OF
THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008



DEBORAH S. STEIN
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER
OF ALTAGAS GENERAL PARTNER INC., DELEGATE OF
THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008

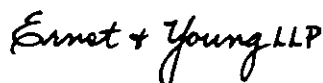
Auditors' Report

TO THE UNITHOLDERS OF ALTAGAS INCOME TRUST

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2007 and 2006 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. 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 AltaGas Income Trust 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.



ERNST & YOUNG LLP
CHARTERED ACCOUNTANTS

February 26, 2008

Calgary, Canada

Consolidated Balance Sheets

As at December 31

(\$ thousands)

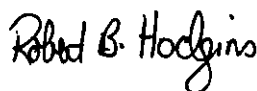
	2007	2006
ASSETS		
Current assets		
Cash and cash equivalents	\$ 12,451	\$ 13,226
Accounts receivable	191,879	224,533
Inventory	130	61
Customer deposits	24,369	16,304
Risk management (note 12)	66,811	-
Other current assets	9,714	9,277
	305,354	263,401
Capital assets (notes 4 and 21)	682,322	677,941
Energy services arrangements, contracts and relationships (note 5)	95,716	103,330
Goodwill (note 6)	18,260	18,260
Risk management (note 12)	33,640	-
Long-term investments and other assets (note 7)	64,509	46,643
	\$ 1,199,801	\$ 1,109,575
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 177,802	\$ 200,882
Distributions payable to unitholders	10,167	9,588
Short-term debt (note 8)	655	-
Current portion of long-term debt (note 9)	1,234	1,147
Customer deposits	24,369	16,304
Deferred revenue	1,718	788
Risk management (note 12)	60,848	-
Other current liabilities	9,321	10,982
	286,114	239,691
Long-term debt (note 9)	218,845	264,340
Asset retirement obligations (note 10)	18,811	23,350
Future income taxes (note 11)	58,229	51,252
Risk management (note 12)	30,166	-
Other long-term liabilities	2,948	1,526
	615,113	580,159
Unitholders' equity (notes 13 and 14)	584,688	529,416
	\$ 1,199,801	\$ 1,109,575

Commitments (notes 8, 9, 12, 16 and 18)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:


DAVID W. CORNHILL
DIRECTOR


ROBERT B. HODGINS
DIRECTOR

Consolidated Statements of Income and Accumulated Earnings

For the years ended December 31

(\$ thousands except per unit amounts and number of units)

	2007	2006
Revenue		
Operating	\$ 1,422,242	\$ 1,358,189
Unrealized gains on risk management (note 12)	1,115	-
Other	5,037	4,415
	1,428,394	1,362,604
Expenses		
Cost of sales	1,104,399	1,043,691
Operating and administrative	150,297	145,788
Amortization:		
Capital assets	39,477	38,377
Energy services arrangements, contracts and relationships	7,614	7,484
Goodwill impairment (note 6)	-	600
	1,301,787	1,235,940
Operating income	126,607	126,664
Interest expense (notes 8, 9 and 12)		
Short-term debt	491	270
Long-term debt	11,394	13,012
Income before income taxes	114,722	113,382
Income tax expense (recovery) (note 11)	5,928	(1,129)
Net income	108,794	114,511
Accumulated earnings, beginning of year	401,618	287,107
Accumulated earnings, end of year	\$ 510,412	\$ 401,618
Net income per unit (note 15)		
Basic	\$ 1.90	\$ 2.06
Diluted	\$ 1.89	\$ 2.06
Weighted average number of units outstanding (thousands) (note 14)		
Basic	57,382	55,469
Diluted	57,420	55,516

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income

For the year ended December 31

(\$ thousands)

2007

Net income	\$ 108,794
Other comprehensive income, net of tax (note 12)	
Unrealized net gains on available for sale financial assets	17,902
Unrealized net gains on derivatives designated as cash flow hedges	7,051
Reclassification to net income of net loss on derivatives designated as cash flow hedges pertaining to prior periods	4,850
	29,803
Comprehensive income	\$ 138,597
Accumulated other comprehensive income, beginning of year	—
Adjustment resulting from adoption of new financial instrument accounting standards (note 2)	(2,634)
Other comprehensive income, net of tax	29,803
Accumulated other comprehensive income, end of year	\$ 27,169

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31

(\$ thousands)

	2007	2006
Cash from operations		
Net income	\$ 108,794	\$ 114,511
Items not involving cash:		
Amortization	47,091	45,861
Accretion of asset retirement obligations (note 10)	1,474	1,430
Unit-based compensation (note 14)	553	482
Future income tax expense (recovery) (note 11)	5,631	(1,181)
Gain on sale of assets	57	-
Equity income	(2,274)	(3,967)
Distributions from equity investments	1,490	2,950
Goodwill impairment (note 6)	-	600
Unrealized gains on risk management (note 12)	(1,115)	-
Other	1,199	994
Funds from operations	162,900	161,680
Asset retirement obligations settled (note 10)	(346)	(560)
Net change in non-cash working capital (note 17)	20,725	(14,260)
	183,279	146,860
Investing activities		
Increase in customer deposits	(8,065)	(933)
Decrease in note receivable	5,100	-
Acquisition of capital assets	(65,065)	(73,042)
Disposition of capital assets	9,759	509
Disposition of energy services arrangements, contracts and relationships	-	36
Acquisition of long-term investments and other assets	(5,567)	(5,032)
Disposition of long-term investments and other assets	412	-
	(63,426)	(78,462)
Financing activities		
Increase (decrease) in short-term debt	655	(2,710)
Decrease in long-term debt	(45,016)	(829)
Distributions to unitholders	(118,061)	(109,954)
Net proceeds from issuance of units (note 14)	41,794	46,636
	(120,628)	(66,857)
Change in cash and cash equivalents	(775)	1,541
Cash and cash equivalents, beginning of year	13,226	11,685
Cash and cash equivalents, end of year	\$ 12,451	\$ 13,226

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(Tabular amounts in thousands of dollars unless otherwise indicated.)

1. Structure of AltaGas Income Trust

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

2. Summary of Significant Accounting Policies

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

Basis of Presentation

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

Until second quarter 2007 AltaGas accounted for its investment in Taylor NGL Limited Partnership (Taylor) using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income (OCI) (see note 12).

Changes in Accounting Policies

Effective January 1, 2007 the Trust adopted the new CICA Handbook accounting requirements for 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". In accordance with the transitional provisions for these new standards, these policies were adopted prospectively without restatement of prior periods.

ACCOUNTING CHANGES

This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements of the Trust.

FINANCIAL INSTRUMENTS

All financial instruments, including derivatives, are included on the balance sheet initially at fair value. The financial assets are classified as held for trading, held to maturity, loans and receivables, or available for sale. Financial liabilities are classified as held for trading or other financial liabilities. Subsequent measurement is determined by classification.

Held for trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options and forwards. These financial instruments are initially accounted for at their fair value and changes to fair value are recorded in income. Held to maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust did not have any held to maturity financial instruments at December 31, 2007. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications.

Available for sale instruments are initially accounted for at their fair value and changes to fair value are recorded through OCI. Income earned from these investments is included in Revenue.

Other financial liabilities not classified as held for trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected purchase, sale or usage requirements exception, are carried on the balance sheet at fair value. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives. The Trust did not identify any embedded derivatives requiring bifurcation.

Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. Effective January 1, 2007 the Trust reclassified \$1.1 million of unamortized deferred financing costs from Other current assets and Long-term investments and other assets to Long-term debt as a result of adopting the new standards. The reclassification of transaction costs has no impact on earnings. Effective January 1, 2007 the Trust began amortizing these costs using the effective interest rate method. Previously, these costs were amortized on a straight-line basis over the life of the debt.

HEDGES

The new standard specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed and where the impacts should be recorded. The standard introduces three specific types of hedging relationships: fair value hedges, cash flow hedges and hedges of a net investment in self-sustaining foreign operations.

As part of its asset and liability management, the Trust uses derivatives for hedging positions to reduce its exposure to commodity price and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The Trust uses cash flow hedges to reduce its exposure to fluctuations in interest rates and changes in commodity prices. The effective portion of changes in the value of cash flow hedges is recognized in Other comprehensive income. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income in the same financial category as the underlying transaction. Gains or losses from cash flow hedges that have been included in Accumulated other comprehensive income are included in net income when the underlying transaction has occurred or becomes probable of not occurring. The maximum length of time the Trust is hedging its exposure to variability in future cash flows is 10 years.

COMPREHENSIVE INCOME AND EQUITY

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income which consists of earnings and the effective portion of changes in unrealized gains and losses related to available for sale assets and cash flow hedges. In addition, as required by Section 3251, the Trust now presents separately in its Unitholders' equity note the changes for each of its components of Unitholders' equity. A new component, Accumulated other comprehensive income, and a one-time transition adjustment have been added to the Trust's Unitholders' equity as a result of the implementation of this new standard (see note 12).

NET EFFECT OF ACCOUNTING POLICY CHANGES

The net effect to the Trust's financial statements at January 1, 2007 resulting from the above mentioned changes in accounting policies is as follows:

Balance Sheet Account Affected

	Increase (Decrease)
Current assets – risk management	\$ 59,866
Other current assets	(451)
Non-current assets	47,942
Long-term investments and other assets	(793)
Current liabilities – risk management	69,618
Long-term debt	(1,082)
Long-term liabilities – risk management	48,359
Future income tax liability	(7,450)
Unitholders' equity – Transition amount on adoption of new accounting standards, net of tax	(247)
Unitholders' equity – Accumulated other comprehensive income, net of tax	(2,634)

The unrealized gains and losses included in the Transition amount and in Accumulated other comprehensive income were recorded net of income tax recoveries of \$4.6 million and \$2.9 million, respectively.

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Inventory

Inventory consists of materials and supplies and is valued at the lower of average cost and replacement cost.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. The corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Repairs and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets.

Field Gathering and Processing (FG&P)

Gathering and processing assets	15 – 25 years
Other assets	1 – 5 years

Extraction and Transmission (E&T)

Extraction and transmission assets	15 – 40 years

Power Generation

Assets under capital lease	10 years

Energy Services

Energy services assets	unit of production
Other assets	1 – 5 years

Corporate

Other assets	1 – 5 years

Leases are classified as either capital or operating. Leases which transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term liability.

Energy Services Arrangements, Contracts, Relationships and Amortization

Energy services arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18 – 49 months
Energy services relationships	15 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC Power Partnership (ASTC). ASTC is committed to purchase all of the power from the two 353-megawatt (MW) capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. The Sundance B PPAs required a capital outlay to acquire. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded when delivered.

The Genesee power purchase arrangement had the right to generating capacity at a regulated Alberta generating unit for a three-year period that ended March 31, 2006. This PPA required no capital outlay but included monthly capacity charges, and these amounts were recorded as cost of sales. Revenue from the sale of the committed power was recorded when delivered.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp. (iQ2), PremStar Energy Canada Ltd., ECNG Canada Ltd. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

Goodwill

Goodwill represents that portion of the purchase price on acquisition which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of goodwill is determined. Any excess of the carrying value of goodwill over its implied fair value is recorded as an impairment charge to income.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available for sale. Available for sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the income statement.

In the E&T segment, certain assets have an indeterminate life and thus a future retirement obligation is not recognized.

Revenue Recognition

In the FG&P segment, revenue is recorded as the services are rendered. In the Power Generation and Energy Services segments, revenue is recognized at the time the product or service is delivered. Within the E&T segment, extraction revenue is recognized at the time the product or service is delivered and transmission revenue is recorded as the services are rendered. Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the related sale occurs or when the underlying financial asset or financial liability is removed from the balance sheet. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held for trading financial assets and liabilities and the Trust's revolving operating credit facility are expensed as incurred. For financial instruments classified as other than held for trading, transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Recognition Date

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in Net income or in OCI as appropriate.

Effective Interest Method

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

Unit-Based Compensation Plans

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

Pension Plans and Retiree Benefits

The cost of defined benefit pension and other retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost of the benefit is the sum of the individual current service costs and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans is nine to 11 years. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable on income in a particular taxation year that is not paid or payable to the unitholders in such taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense and future income tax liability. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the year. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, as a result of matters that are inherently uncertain, include among others, the fair value of certain assets including long-lived assets and goodwill; recoverability of investments; litigation; environmental and asset retirement obligations; financial instruments; pensions and other post-retirement benefits; unit based compensation; and income taxes. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Future Accounting Changes

SECTION 1535 "CAPITAL DISCLOSURES"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3031 "INVENTORIES"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3862 "FINANCIAL INSTRUMENTS – DISCLOSURES" AND SECTION 3863 – "FINANCIAL INSTRUMENTS – PRESENTATION"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over a five-year transition period with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

3. Subsequent Events

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders \$11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of \$245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, \$27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was \$598.7 million, including \$256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$ 11 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:

Cost of 8.9% investment in Taylor originally owned by AltaGas		24,672
Purchase price for the remaining 91.1% of Taylor units		
Cash considerations	256,281	
Units	198,862	
Estimated transaction costs	11,000	
Equity portion of Taylor convertible debentures	2,127	468,270
Total consideration		\$ 492,942

Purchase price allocation for 100% of Taylor:

Assets acquired		
Current assets	30,739	
Capital assets	590,030	
Energy service arrangements, contracts and relationships	83,900	
Goodwill	108,191	
Long-term investments and other assets	4,640	817,500
Less Liabilities assumed		
Current liabilities	31,202	
Long-term debt	110,241	
Convertible debentures	22,171	
Asset retirement obligations	14,350	
Future income taxes	144,028	
Future employee obligations	2,542	
Risk management	24	324,558
		\$ 492,942

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of \$256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately \$610 million compared to \$220.7 million as at December 31, 2007.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for \$4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at \$24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

4. Capital Assets

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Field Gathering and Processing						
Field gathering and processing assets	\$ 569,944	\$ (148,297)	\$ 421,647	\$ 558,411	\$ (128,643)	\$ 429,768
Other assets	4,416	(2,161)	2,255	2,860	(1,402)	1,458
Extraction and Transmission						
Extraction and transmission assets	255,810	(46,078)	209,732	250,933	(38,023)	212,910
Power Generation						
Capital lease (note 9)	13,798	(4,596)	9,202	13,798	(3,216)	10,582
Power generation assets	22,013	-	22,013	-	-	-
Energy Services						
Energy services assets	9,693	(896)	8,797	30,177	(15,250)	14,927
Other assets	2,018	(156)	1,862	1,990	(385)	1,605
Corporate						
Other assets	19,230	(12,416)	6,814	16,962	(10,271)	6,691
	\$ 896,922	\$ (214,600)	\$ 682,322	\$ 875,131	\$ (197,190)	\$ 677,941

Interest capitalized on long-term capital construction projects for the year ended December 31, 2007 was \$0.8 million (December 31, 2006 – \$nil). At December 31, 2007 the Trust had spent approximately \$42.6 million (December 31, 2006 – \$14.9 million) on capital projects under construction that were not yet subject to amortization.

5. Energy Services Arrangements, Contracts and Relationships

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services arrangements and contracts	\$ 115,071	\$ (37,717)	\$ 77,354	\$ 115,071	\$ (31,497)	\$ 83,574
Energy services relationships	20,892	(2,530)	18,362	20,892	(1,136)	19,756
	\$ 135,963	\$ (40,247)	\$ 95,716	\$ 135,963	\$ (32,633)	\$ 103,330

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding short-term marketing contracts.

6. Goodwill

	2007	2006
Balance, beginning of year	\$ 18,260	\$ 18,860
Goodwill impairment	-	(600)
Balance, end of year	\$ 18,260	\$ 18,260

In 2006 through its annual goodwill impairment testing AltaGas determined that the fair value of an investment in a business ancillary to the FG&P segment was less than the book value and reduced the carrying value by \$0.6 million.

7. Long-Term Investments and Other Assets

	2007	2006
Units of public trusts	\$ -	\$ 375
Equity accounted investments in public entities	11,813	40,071
Cost accounted investments in public entities	44,746	-
Deferred debt costs, net of amortization	-	759
Deferred development costs	7,242	4,332
Loans receivable – BMWLP	-	700
Warrants	286	-
Other	422	406
	\$ 64,509	\$ 46,643

At December 31, 2007 the quoted market value of the holdings of publicly traded entities was approximately \$54.2 million (December 31, 2006 – \$50.0 million).

The Trust accounts for its interests in AltaGas Utility Group Inc. (Utility Group) as an equity investment.

Until second quarter 2007 AltaGas accounted for its investment in Taylor using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor is designated as available for sale and is measured at fair value with the changes in fair value recorded in OCI (see note 12).

In 2006 the Trust formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation and the GreenWing Energy Development Limited Partnership (GEDLP) with GreenWing Energy Management Ltd. In 2007 the Trust acquired 100 percent ownership of BMWLP. Through BMWLP and GEDLP, the Trust invested \$3.8 million (December 31, 2006 – \$4.3 million) in the development of wind power projects. Amortization of these deferred development costs will occur based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

In 2007 AltaGas sold Cedar Energy Partnership in exchange for a \$12 million promissory note and received 1 million warrants of the purchaser, each of which will allow AltaGas to subscribe for and purchase one fully paid and non-assessable common share in the capital of the purchaser for a three-year term ending June 1, 2010. The remaining \$6.5 million of the promissory note is included in Other current assets.

8. Short-Term Debt

At December 31, 2007 the Trust held a \$50.0 million (December 31, 2006 – \$50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. At December 31, 2007 the Trust had prime loans of \$0.7 million (December 31, 2006 – \$nil) and letters of credit of \$2.8 million (December 31, 2006 – \$3.0 million) outstanding against the facility.

The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent).

9. Long-Term Debt

	2007	2006
Operating loans	\$ 10,045	\$ 154,306
Capital lease obligations	10,034	11,181
Medium-term notes	200,000	100,000
	220,079	265,487
Less current portion	1,234	1,147
	\$ 218,845	\$ 264,340

Letter of Credit Facility

At December 31, 2007 the Trust held a \$75.0 million (December 31, 2006 – \$75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to \$25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2007 the Trust had letters of credit of \$61.7 million (December 31, 2006 – \$63.3 million) outstanding against the extendible revolving-term letter of credit facility.

Operating Loans

At December 31, 2007 the Trust held a \$300.0 million (December 31, 2006 – \$300.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw. On September 30, 2007 AltaGas negotiated the extension of the maturity date of this facility to September 30, 2010. On December 14, 2007 AltaGas negotiated minor amendments to the facility in order to facilitate the closing of the Taylor acquisition.

At December 31, 2007 the Trust had drawn \$10.0 million (December 31, 2006 – \$154.3 million) against the facility. The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent). The average rate on the Trust's bankers' acceptances at December 31, 2007 was 5.2 percent (December 31, 2006 – 5.0 percent).

Medium-Term Notes

On April 29, 2005 AltaGas filed a Universal Shelf Prospectus pursuant to which the Trust may issue up to an aggregate of \$500.0 million of trust units and debt securities over a 25-month period. AltaGas filed a prospectus supplement on August 23, 2005 establishing AltaGas' medium-term note (MTN) program. On August 30, 2005 \$100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually. The proceeds of the issue were used to repay bank debt. On January 19, 2007 AltaGas issued a further \$100.0 million of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012. The net proceeds were used to pay down existing bank indebtedness and for general corporate purposes.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments over the next five years as follows:

2008	\$ 1,878
2009	1,878
2010	1,878
2011	1,878
2012	1,878
Thereafter	3,136
	12,526
Less imputed interest at 6.85%	2,492
Present value of minimum lease payments	10,034
Less current portion	1,234
	\$ 8,800

Interest expense on capital leases was \$0.7 million in 2007 (December 31, 2006 – \$0.8 million).

10. Asset Retirement Obligations

	2007	2006
Balance, beginning of year	\$ 23,350	\$ 16,982
New obligations	423	696
Obligations settled	(346)	(560)
Obligations disposed	(4,006)	–
Revision in estimated cash flow	(2,084)	4,802
Accretion expense	1,474	1,430
Balance, end of year	\$ 18,811	\$ 23,350

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2007 was \$52.4 million (December 31, 2006 – \$57.0 million). The asset retirement obligations have been recorded in the financial statements at estimated values discounted at rates between 5.6 percent and 8.3 percent and are expected to be incurred between 2010 and 2040. The majority of the costs are expected to be incurred between 2025 and 2035. No assets have been legally restricted for settlement of the estimated liability.

11. Income Taxes

Taxation of the Trust

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense of \$5.4 million (including \$0.1 million in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

	2007	2006
Income before taxes – consolidated	\$ 114,722	\$ 113,382
Financial instruments – net	(1,115)	–
Income before financial instruments and taxes	113,607	113,382
Income from AltaGas Income Trust distributed to unitholders	(92,544)	(92,385)
Income before income taxes – operating subsidiaries	21,063	20,997
Statutory income tax rate (%)	32.12	34.49
Expected taxes at statutory rates	6,765	7,242
Add (deduct) the tax effect of:		
SIFT tax	5,365	–
Financial instruments	1,561	–
Resource allowance	–	(1,048)
Rate reductions applied to future income tax liabilities	(7,256)	(7,822)
Permanent differences between accounting and tax bases of assets and liabilities	294	166
Non-taxable portion of capital gains on disposition of assets and investments	(1,634)	–
Other	833	333
Income tax provision (recovery)		
Current	297	7
Future	266	(1,136)
Future SIFT	5,365	–
	\$ 5,928	\$ (1,129)
Effective income tax rate (%)	5.17	(1.00)

AltaGas' income taxes are calculated according to government tax laws and regulations which result in different values for certain assets and liabilities for income tax purposes than for financial statement purposes. The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between tax values and book carrying values on the operating subsidiaries' balance sheets at substantively enacted tax rates. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements. In the case of AltaGas, these future income taxes are not expected to result in cash taxes being paid due to the expectation of continued future intercompany interest deductions at the operating subsidiary level.

As at December 31, future income taxes were composed of the following:

	2007	2006
Capital assets	\$ 31,101	\$ 14,448
Deferred debt charges	53	(26)
Unit issue costs	(635)	(1,209)
Partnerships	26,878	41,522
Deferred compensation	(2,092)	(3,408)
Financial instruments	2,973	–
Other	(49)	(75)
	\$ 58,229	\$ 51,252

12. Financial Instruments and Financial Risk Management

In the course of normal operations the Trust purchases and sells natural gas, natural gas liquids and power commodities and issues short and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

At December 31, 2007 all derivatives, other than those that meet the expected purchase, sale or usage requirements exception, were carried on the balance sheet at fair value. The fair value of power and natural gas derivatives was calculated using estimated forward prices for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates.

At December 31, 2007 the fair value of the Trust's assets and liabilities was as follows:

Summary of Fair Values	Current	Long-term	Total
Financial assets			
Held for trading	\$ 54,928	\$ 28,272	\$ 83,200
Available for sale	-	44,746	44,746
Loans and receivables	208,581	-	208,581
	263,509	73,018	336,527
Cash flow hedges	11,883	5,368	17,251
	\$ 275,392	\$ 78,386	\$ 353,778
Financial liabilities			
Held for trading	\$ 56,720	\$ 30,079	\$ 86,799
Other financial liabilities	168,479	213,608	382,087
	225,199	243,687	468,886
Cash flow hedges	4,128	87	4,215
	\$ 229,327	\$ 243,774	\$ 473,101

Unrealized Income

The impact on net income in 2007 from the adoption of the new financial instruments standards resulted in a \$1.1 million unrealized gain.

Other Comprehensive Income

As a part of its hedging program, the Trust uses certain derivative financial instruments to manage risks. An after-tax unrealized loss of \$4.8 million was reclassified to net income. Of the \$27.2 million gain deferred in Accumulated other comprehensive income (AOCI) at December 31, 2007, a \$5.4 million gain is expected to be reclassified to net income in the next 12 months.

The available for sale assets included in the balance sheet caption, Long-term investments and other assets are recognized at fair value, net of tax, in OCI.

Effective January 1, 2007 the Trust began offsetting long-term debt transaction costs against the associated debt and began amortizing these costs using the effective interest rate method. Previously these costs were amortized on a straight-line basis over the life of the debt instrument to which they pertained. There was no material effect on the Trust's financial statements as a result of this change in policy. The effective interest rate for the medium-term notes issued in 2005 and 2007 was 4.54 percent and 5.11 percent, respectively.

Commodity Price Risk Management

NATURAL GAS

The Trust purchases and sells natural gas to its customers. The fixed-price and market-price contracts for both the purchase and sale of natural gas extend to 2012.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per GJ) ⁽¹⁾	Period (months)	Notional volume (GJ)		Fair value
			Sales	Purchases	
Commodity forward	\$2.16 to \$10.37	1 – 55	105,375,003	–	\$ (17,775)
Commodity forward	\$2.16 to \$10.37	1 – 55	–	105,375,003	\$ 14,754

⁽¹⁾ Certain of the contracts are indexed and as such a price range is not provided.

In 2007 an unrealized gain of \$2.0 million was recognized from the Trust's natural gas risk management activities.

NATURAL GAS LIQUIDS

The Trust entered into a series of swaps to lock in a portion of the margin exposed to natural gas liquids (NGL) frac spread.

At December 31, 2007 the Trust had the following contracts outstanding:

Product	Fixed price	Period (months)	Notional volume		Fair value
			Sales	Purchases	
Propane	\$1.2825 to 1.4725 US/gallon	1 – 12	9,677,178 gallon	–	\$ (1,156)
Normal butane	\$1.4950 to 1.7000 US/gallon	1 – 12	2,612,064 gallon	–	(685)
WTI	\$83.20 to 89.10 US/Bbl	1 – 12	27,489 Bbls	–	(143)
Natural gas	\$6.455 to 6.550/GJ	1 – 12	–	1,382,591 GJ	\$ 159

In 2007 the Trust recognized an unrealized loss of \$0.6 million from the Trust's NGL risk management activities.

POWER

Under the power purchase arrangements AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2007 the Trust had no intention to terminate any contracts prior to maturity.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair value
			Sales	Purchases	
Commodity forward	\$79.00 to \$80.60	1 – 3	2,160	–	\$ (28)
Commodity forward	\$63.25 to \$68.00	1 – 3	–	2,160	\$ 31

The Trust's power risk management activities from financial contracts not included in the hedging program had an unrealized loss of \$40,248.

At December 31, 2007 the Trust had the following commodity swaps and collars outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair value
			Sales	Purchases	
Swaps and collars	\$65.00 to \$88.00	1 – 24	1,626,624	–	\$ 10,932
Swaps and collars	\$56.50 to \$56.50	1 – 120	–	263,016	\$ 3,339

At December 31, 2007 the Trust had the following heat rate hedges outstanding:

Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh)		Fair value
			Sales	Purchases	
Natural gas (per GJ)	\$6.08 to \$6.17	1	–	79,050	\$ 17,968
Power (per MWh)	\$89.00 to \$138.00	1	6,510	–	\$ 170,019

In 2007 an unrealized gain of \$0.2 million was recognized from the Trust's heat rate hedging activities.

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forward contracts. For 2007 the Trust's foreign exchange risk management activities had an unrealized loss of \$0.7 million.

Interest Rate Risk Management

To hedge against the effect of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. In January 2007 the Trust unwound certain of these interest rate swaps as a result of the issue of \$100 million of medium-term notes and recorded a gain of \$0.4 million. In the third quarter the Trust terminated the hedge relationship on certain swap agreements resulting in an immaterial unrealized gain. The remaining interest rate swaps have an average remaining term of 2 to 15 months and a weighted average interest rate of 3.56 percent. The Trust's interest rate risk management activities resulted in an unrealized gain of \$0.2 million and fair market value position of \$0.2 million at December 31, 2007.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a derivative in which the Trust has an unrealized gain fails to perform according to the terms of the contract.

Credit exposure is minimized by entering into transactions with creditworthy counterparties in accordance with established credit policies and practices. At December 31, 2007 AltaGas did not have a significant concentration of credit risk with any single counterparty to financial instruments.

13. Unitholders' Equity

	2007	2006
Unitholders' capital (note 14)	\$ 505,544	\$ 463,750
Contributed surplus	3,875	3,322
Accumulated earnings	510,412	401,618
Accumulated dividends	(41,114)	(41,114)
Accumulated unitholders' distributions declared ⁽¹⁾	(391,103)	(272,464)
Distributions of common shares of Utility Group	(29,848)	(25,696)
Transition adjustment resulting from adopting new financial instruments accounting standards	(247)	–
Accumulated other comprehensive income	27,169	–
	\$ 584,688	\$ 529,416

⁽¹⁾ Accumulated unitholders' distributions paid by the Trust as at December 31, 2007 were \$380.9 million (as at December 31, 2006 – \$262.9 million).

In 2007 the holders of trust units of the Trust and holders of exchangeable partnership units of AltaGas Holding Limited Partnership No. 1 received one common share of Utility Group for every 100 trust or exchangeable units held on August 27, 2007. As part of the distribution plan, any unitholder allocated fewer than 50 common shares of Utility Group received cash. The number of common shares of Utility Group distributed to unitholders was 577,416, which reduced unitholders equity by \$4.2 million. This distribution resulted in a 27 percent reduction of the Trust's interest in Utility Group to 19.6 percent.

14. Unitholders' Capital

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange is at the option of the unitholder at anytime, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. After May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2005	52,505,514	\$ 404,854
Units issued for cash on exercise of options	9,150	127
Units issued under DRIP ⁽¹⁾	1,745,630	46,509
Units issued for exchangeable units	53,258	305
December 31, 2006	54,313,552	451,795

Exchangeable Units Issued and Outstanding:

December 31, 2005 issued by AltaGas LP #1	2,142,072	12,260
AltaGas LP #1 units redeemed for trust units	(53,258)	(305)
December 31, 2006	2,088,814	11,955
Issued and outstanding at December 31, 2006	56,402,366	\$ 463,750

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2006	54,313,552	\$ 451,795
Units issued for cash on exercise of options	3,400	68
Units issued under DRIP ⁽¹⁾	1,692,128	41,726
Units issued for exchangeable units	48,358	277
December 31, 2007	56,057,438	493,866

Exchangeable Units Issued and Outstanding:

December 31, 2006 issued by AltaGas LP #1	2,088,814	11,955
AltaGas LP #1 units redeemed for trust units	(48,358)	(277)
December 31, 2007	2,040,456	11,678
Issued and outstanding at December 31, 2007	58,097,894	\$ 505,544

⁽¹⁾ Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan.

The Trust has an employee unit option plan under which both employees and directors are eligible to receive grants. At December 31, 2007, 10 percent of units outstanding were reserved for issuance under the plan. To December 31, 2007 options granted under the plan generally had a term of 10 years to expiry and vested no longer than over a four-year period.

At December 31, 2007 outstanding options were exercisable at various dates to the year 2017 (December 31, 2006 – 2016). Options outstanding under the plan have a weighted average exercise price of \$26.36 (December 31, 2006 – \$27.23) and a weighted average remaining term of 8.76 years (December 31, 2006 – 9.23 years). As at December 31, 2007 the unexpensed fair value of unit option compensation cost associated with future periods was \$0.7 million (December 31, 2006 – \$0.9 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding			
	2007		2006	
	Number of options	Exercise price ⁽¹⁾	Number of options	Exercise price ⁽¹⁾
Unit options outstanding, beginning of year	923,550	\$ 27.23	359,200	\$ 24.53
Granted	548,500	25.31	636,500	28.60
Exercised	(3,400)	20.06	(9,150)	13.93
Cancelled	(158,250)	27.94	(63,000)	27.53
Unit options outstanding, end of year	1,310,400	\$ 26.36	923,550	\$ 27.23
Unit options exercisable, end of year	331,425	\$ 25.50	106,513	\$ 20.48

⁽¹⁾ Weighted average.

A summary of the plan as at December 31, 2007:

	Options outstanding			Options exercisable	
	Number outstanding ⁽¹⁾	Exercise price ⁽²⁾	Remaining contractual life ⁽³⁾	Number exercisable ⁽¹⁾	Exercise price ⁽²⁾
\$5.00 – \$7.00	9,000	\$ 6.10	2.45	9,000	\$ 6.10
\$7.01 – \$15.50	28,500	10.26	5.15	28,500	10.26
\$15.51 – \$25.08	416,400	24.77	9.23	54,300	24.16
\$25.09 – \$29.50	856,500	27.86	8.72	239,625	28.35
	1,310,400	\$ 26.36	8.76	331,425	\$ 25.50

⁽¹⁾ As at December 31, 2007.

⁽²⁾ Weighted average.

⁽³⁾ Weighted average number of years.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted-average assumptions for grants as follows:

	2007	2006
Risk-free interest rate (%)	3.29	4.36
Expected lives (years)	10	10
Expected volatility (%)	21.71	20.89
Annual distribution per unit (\$)	2.04	1.981

Units Outstanding ⁽¹⁾	2007	2006
Number of units – basic ⁽²⁾	57,382,209	55,468,969
Dilutive stock options	37,632	47,216
Number of units – diluted ⁽²⁾	57,419,841	55,516,185

⁽¹⁾ Includes exchangeable units.

⁽²⁾ Weighted average.

In 2004 AltaGas implemented a unit-based compensation plan which awards phantom units to certain employees. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2007 in respect of this plan was \$5.1 million (December 31, 2006 – \$6.7 million). As at December 31, 2007 the unexpensed fair value of unit-based compensation costs associated with future periods was \$14.2 million (December 31, 2006 – \$9.9 million).

15. Income Per Unit

The following table summarizes the computation of net income per unit:

	2007	2006
Numerator:		
Numerator for basic income per unit	\$ 108,794	\$ 114,511
Numerator for basic and diluted income per unit	\$ 108,794	\$ 114,511
Denominator:		
Weighted-average number of units	57,382	55,469
Dilutive unit options	38	47
Denominator for diluted income per unit	57,420	55,516
Basic income per unit	\$ 1.90	\$ 2.06
Diluted income per unit	\$ 1.89	\$ 2.06

16. Commitments

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment are estimated as follows:

2008	\$ 3,887
2009	3,606
2010	3,181
2011	2,798
2012	2,499
	\$ 15,971

Under the terms of a 1997 long-term gas supply contract, the Trust is committed to supply natural gas for prices ranging from \$2.34/Mcf in 2007 to \$2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. In 1999, one of those producers defaulted on its obligation under its gas supply contract, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

In 1999 the Trust acquired a right to purchase natural gas from specific reserves for \$0.05/Mcf for the life of the reserves. The production from these reserves was 1,039 Mcf/d in 2007 (2006 – 1,321 Mcf/d).

In 2007 AltaGas entered into a supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind project. The Trust has an obligation to pay approximately \$144 million before the supply and installation is complete. The Trust has also entered into other supply agreements to pay approximately \$6 million for equipment and construction costs associated with the Bear Mountain Wind project.

17. Net Change in Non-Cash Working Capital

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

	2007	2006
Accounts receivable	\$ 32,654	\$ (3,849)
Inventory	(69)	34
Other current assets	6,065	(4,856)
Accounts payable and accrued liabilities	(23,080)	(14,719)
Customer deposits	8,065	933
Deferred revenue	930	788
Other current liabilities	(1,661)	209
	22,904	(21,460)
Less decrease (increase) in capital costs payable	(2,179)	7,200
Net change in non-cash working capital related to operations	\$ 20,725	\$ (14,260)

The following cash payments have been included in the determination of earnings:

	2007	2006
Interest paid	\$ 12,078	\$ 13,521
Income taxes paid	\$ 181	\$ 62

18. Pension Plans and Retiree Benefits

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all regular employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was \$1.4 million for the year ended December 31, 2007 (December 31, 2006 – \$1.3 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Effective January 1, 2005 the plan was amended in respect of certain employees who transferred employment from AltaGas Utilities Inc., a then wholly owned subsidiary to the Trust during most of 2005. Assets and liabilities were transferred to Parts III and IV of the Salaried Employees' Pension Plan for three such employees during 2006.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2007 and 2006 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was \$1.9 million (December 31, 2006 – \$1.9 million). At December 31, 2007, the plan had an accrued benefit liability recognized in the financial statements of \$0.3 million (December 31, 2006 – \$0.3 million).

For the year ended December 31, 2007, the net pension cost was a recovery of \$15,000 (December 31, 2006 – recovery of \$11,000).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan which provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was \$3.0 million (December 31, 2006 – \$2.1 million). At December 31, 2007 the plan had an accrued benefit liability recognized in the financial statements of \$1.9 million (December 31, 2006 – \$1.0 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a Retirement Compensation Arrangement Trust account.

For the year ended December 31, 2007 the net pension expense was \$1.0 million (December 31, 2006 – \$0.8 million).

The following table summarizes the details of the defined benefit plans:

	2007	2006
Accrued benefit obligation		
Balance, beginning of year	\$ 4,079	\$ 2,987
Net transfer in	-	165
Actuarial loss (gain)	(73)	96
Current service cost	738	657
Interest cost	240	174
Benefits paid	(83)	-
Balance, end of year	4,901	4,079
Plan assets		
Fair value, beginning of year	1,729	1,409
Net transfers in	-	164
Actual return (loss) on plan assets	(71)	144
Employer contributions	11	12
Benefits paid	(83)	-
Fair value, end of year	1,586	1,729
Funded deficit	(3,315)	(2,350)
Unamortized past service costs	778	855
Unamortized net actuarial loss	330	227
Accrued benefit asset (liability) recognized in the financial statements	\$ (2,207)	\$ (1,268)

	2007	2006
Significant actuarial assumptions used as at December 31		
Discount rate (%)	5.50	5.25 – 5.50
Expected long-term rate of return on plan assets (%)	6.00 – 6.75	6.00 – 6.75
Rate of compensation increase (%)	3.50 – 4.00	3.50 – 4.00
Average remaining service life of active employees (years)	9 – 11	9 – 12
Net benefit plan expense for the year		
Current service cost and expenses	\$ 739	\$ 657
Interest cost	240	174
Actual loss (return) on plan assets	71	(144)
Actuarial loss (gain)	(73)	96
Costs arising in the year	977	783
Differences between costs arising in the year and costs recognized in the year in respect of:		
Return on plan assets	(188)	49
Actuarial gains (loss)	84	(87)
Past service costs	77	77
Net periodic benefit plan costs recognized	\$ 950	\$ 822

19. Related Party Transactions

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

	2007	2006
Fees for administration, management and other services paid by:		
Utility Group to the Trust	\$ 29	\$ 30
The Trust to Utility Group	\$ 445	\$ 1,001
Natural gas sales by the Trust to Utility Group subsidiaries	\$ 83,370	\$ 84,046
Fees for operating services paid by Utility Group subsidiaries	\$ 341	\$ 469
Transportation services provided by Utility Group subsidiaries	\$ 477	\$ 560
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	\$ 85	\$ 83

The resulting amounts due from and to related parties are non-interest bearing and are related to transactions in the normal course of business.

Included in accounts receivable at December 31, 2007 was \$13.5 million (December 31, 2006 – \$13.8 million) due to the Trust from related parties.

Included in accounts payable at December 31, 2007 is \$50,000 (December 31, 2006 – \$0.7 million) due from the Trust to related parties.

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for \$9.0 million to execute the divestiture of non-core production assets.

20. Joint Ventures

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	2007	2006
Proportionate share of operating income		
Revenues	\$ 201,124	\$ 234,243
Expenses	131,220	156,649
	\$ 69,904	\$ 77,594
Proportionate share of net assets		
Current assets	\$ 33,135	\$ 44,386
Capital assets	91,238	93,917
Energy services arrangements, contracts and relationships	75,483	81,292
Long-term investments and other assets	3,643	4,637
Current liabilities	(32,780)	(43,129)
	\$ 170,719	\$ 181,103
Proportionate share of cash flows		
Operating activities	\$ 79,959	\$ 83,367
Investing activities	(571)	(57,826)
Financing activities	(79,388)	(25,541)
	\$ -	\$ -

21. Disposition on Sale of Capital Assets

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for cash, effective July 31, 2007 at the exchange amount of \$9.0 million. The gain on the sale was negligible. In 2007 AltaGas recorded a one-time gain of \$1.5 million from the sale of oil and natural gas production assets for non-monetary consideration totaling \$11.9 million including a promissory note of \$11.6 million. The disposition also resulted in the reduction in the asset retirement obligation by \$3.7 million.

22. Segmented Information

AltaGas is an integrated energy Trust with a portfolio of assets and services used to move energy from the source to the end-user. Transactions among the reporting segments are recorded at fair value. The following describes the Trust's five reporting segments:

- Field Gathering and Processing** – natural gas gathering lines and processing facilities;
- Extraction and Transmission** – ethane and natural gas liquids extraction plants and natural gas and condensate transmission pipelines;
- Power Generation** – coal-fired and gas-fired power output under power purchase arrangements and other agreements;
- Energy Services** – energy management and gas services for natural gas and electricity; and
- Corporate** – the costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management assets and liabilities.

The following tables show the breakdown by segment:

For the year ended December 31, 2007	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	\$ 135,105	\$ 142,938	\$ 182,535	\$ 1,022,506	\$ 5,037	\$ (60,842)	\$ 1,427,279
Unrealized gains (losses) on risk management	-	-	-	-	1,115	-	1,115
Cost of sales	(7,655)	(75,495)	(78,373)	(1,001,599)	-	58,723	(1,104,399)
Operating and administrative	(83,344)	(20,300)	(2,035)	(15,576)	(31,161)	2,119	(150,297)
Amortization	(25,901)	(8,055)	(7,488)	(3,307)	(2,340)	-	(47,091)
Operating income (loss)	\$ 18,205	\$ 39,088	\$ 94,639	\$ 2,024	\$ (27,349)	-	\$ 126,607
Operating income (loss) before unrealized gains (losses) on risk management	\$ 18,205	\$ 39,088	\$ 94,639	\$ 2,024	\$ (28,464)	-	\$ 125,492

Net additions (reductions) to:

Capital assets	\$ 13,213	\$ 4,672	\$ 22,013	\$ (20,457)	\$ 2,349	-	\$ 21,790
Long-term investments and other assets	-	-	\$ (530)	-	\$ 18,396	-	\$ 17,866
Goodwill	\$ 215	\$ 18,045	-	-	-	-	\$ 18,260
Segment assets	\$ 507,876	\$ 241,198	\$ 151,401	\$ 124,702	\$ 174,624	-	\$ 1,199,801

For the year ended December 31, 2006	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	\$ 139,016	\$ 149,143	\$ 199,344	\$ 948,939	\$ 4,415	\$ (78,253)	\$ 1,362,604
Cost of sales	(9,381)	(85,888)	(99,761)	(924,249)	-	75,588	(1,043,691)
Operating and administrative	(80,068)	(20,305)	(1,332)	(17,060)	(29,688)	2,665	(145,788)
Amortization	(23,579)	(7,733)	(7,382)	(4,848)	(2,319)	-	(45,861)
Goodwill impairment	(600)	-	-	-	-	-	(600)
Operating income (loss)	\$ 25,388	\$ 35,217	\$ 90,869	\$ 2,782	\$ (27,592)	-	\$ 126,664
Operating income (loss) before unrealized gains (losses) on risk management	\$ 25,388	\$ 35,217	\$ 90,869	\$ 2,782	\$ (27,592)	-	\$ 126,664

Net additions (reductions) to:

Capital assets	\$ 62,295	\$ 4,319	\$ (28)	\$ 1,652	\$ 2,270	-	\$ 70,508
Energy service arrangements, contracts and relationships	-	\$ -	-	\$ (36)	-	-	\$ (36)
Long-term investments and other assets	-	\$ -	\$ 4,332	-	\$ 1,390	-	\$ 5,722
Goodwill	\$ 215	\$ 18,045	-	-	-	-	\$ 18,260
Segment assets	\$ 528,636	\$ 258,480	\$ 140,427	\$ 131,907	\$ 50,125	-	\$ 1,109,575

23. Comparative Figures

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

10-Year Review of Financial and Operating Information

(\$ millions unless otherwise indicated)

	2007	2006	2005	2004
Financial Highlights				
Income Statement				
Revenue	1,428.4	1,362.6	1,502.3	864.6
Net revenue ^{(1) (2)}				
Gathering, Processing and Energy Services	-	-	-	-
Gathering and Processing	-	-	-	160.1
Field Gathering and Processing	127.4	129.7	120.1	-
Extraction and Transmission	67.4	63.2	58.0	-
Power Generation	104.2	99.6	57.8	-
Energy Services	20.9	24.7	23.5	59.9
Natural Gas Distribution ⁽³⁾	-	-	29.0	30.7
Corporate	6.2	4.4	10.9	-
Intersegment elimination	(2.1)	(2.7)	(2.4)	(0.3)
	324.0	318.9	296.9	250.4
EBITDA ⁽¹⁾	173.7	173.1	155.5	133.4
Net income	108.8	114.5	90.3	65.8
Net income per basic unit	\$ 1.90	\$ 2.06	\$ 1.67	\$ 1.33
EBITDA per basic unit ⁽¹⁾	\$ 3.03	\$ 3.12	\$ 2.88	\$ 2.70
Cash Flow				
Funds from operations ⁽¹⁾	162.9	161.7	129.0	108.6
Funds from operations per basic unit ⁽¹⁾	\$ 2.84	\$ 2.91	\$ 2.39	\$ 2.20
Distributions/dividends per unit declared ⁽⁴⁾	\$ 2.065	\$ 1.995	\$ 1.85	\$ 1.31
Balance Sheet				
Capital assets	682.3	677.9	645.4	746.7
Energy services arrangements, contracts and relationships	95.7	103.3	110.9	113.1
Total assets	1,199.8	1,109.6	1,068.3	1,108.6
Short-term debt	0.7	-	2.7	7.0
Long-term debt	220.0	265.5	266.3	352.5
Unitholders' equity	584.7	529.4	478.6	483.5
Unit Data (millions)				
Units outstanding at year-end	58.1	56.4	54.6	53.2
Weighted average units outstanding for the year (basic)	57.4	55.5	54.0	49.4
Ratios (%)				
Return on average equity	19.8	22.7	18.4	15.7
Return on average invested capital	16.2	16.3	13.0	11.6
Debt as a percent of total capitalization	27.4	33.4	36.0	42.6
Operating Results				
Field Gathering and Processing				
Capacity (gross Mmc/d) ⁽⁵⁾	1,023	1,021	962	913
Throughput (gross Mmc/d) ⁽⁶⁾	511	549	573	558
Throughput (gross annual Mmc/d)	527	555	563	560
Capacity utilization (%) ⁽⁶⁾	52	54	60	61
Extraction and Transmission				
Extraction inlet capacity (Mmc/d) ⁽⁵⁾	554	554	539	539
Production (Bbls/d) ⁽⁷⁾	20,108	19,696	19,357	13,436
Transmission volumes (Mmc/d) ^{(8) (9)}	407	400	432	432
Frac spread (\$/Bbl) ^{(7) (10)}	21.38	18.47	9.31	10.51
Power Generation				
Volume of power sold (GWh) ⁽⁷⁾	2,661	2,878	3,466	3,481
Price received on the sale of power (\$/MWh) ⁽⁷⁾	68.59	69.26	54.59	48.77
Alberta Power Pool price (\$/MWh) ⁽⁷⁾	66.84	80.48	70.19	54.54
Energy Services				
Energy management service contracts ⁽⁵⁾	1,466	1,394	1,243	427
Average gas volumes marketed (GJ/d) ⁽¹¹⁾	388,217	327,057	312,272	174,337
Natural Gas Distribution ^{(3) (12)}				
Volume of natural gas distributed				
Sales (Bcf)	-	-	10	14
Transportation (Bcf)	-	-	9	11
Number of customers ⁽⁵⁾	-	-	61,447	60,430
Degree day variance (%) ⁽¹³⁾	-	-	(1.4)	2.6

2003	2002	2001	2000	1999	1998
710.6	492.7	489.8	506.7	257.8	122.1
-	-	111.0	88.5	61.8	36.3
137.8	99.6	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
49.3	44.2	-	-	-	-
30.6	28.9	26.9	28.1	27.2	12.9
-	-	-	-	-	-
(0.4)	(2.8)	(2.9)	(0.3)	(3.1)	(1.4)
217.3	169.9	135.0	116.3	85.9	47.8
121.9	94.8	69.9	57.0	42.8	24.1
38.3	29.4	19.2	17.6	11.3	7.2
\$ 0.84	\$ 0.70	\$ 0.50	\$ 0.46	\$ 0.43	\$ 0.39
\$ 2.68	\$ 2.24	\$ 1.83	\$ 1.50	\$ 1.62	\$ 1.31
90.2	70.8	50.2	40.5	28.6	16.1
\$ 1.98	\$ 1.67	\$ 1.31	\$ 1.06	\$ 1.08	\$ 0.88
\$ 0.38	\$ 0.28	\$ 0.18	-	-	-
677.9	663.4	521.0	453.0	376.9	280.5
101.0	107.0	112.2	-	-	-
919.3	904.9	721.1	581.1	436.5	327.1
4.5	50.6	100.0	-	-	-
392.4	368.9	283.9	216.9	151.9	160.3
363.3	338.6	261.9	250.6	230.8	129.1
45.7	45.2	38.5	38.2	37.8	18.9
45.5	42.3	38.2	38.1	26.4	18.4
10.9	9.8	7.3	7.0	6.6	9.0
11.1	9.3	8.7	8.6	8.4	9.4
52.2	55.3	58.5	45.6	39.0	54.7
861	842	768	712	658	494
523	532	498	434	371	276
520	492	489	418	330	208
61	63	65	61	56	56
349	349	219	211	199	155
7,575	3,399	2,618	3,369	2,198	956
403	106	47	36	26	16
6.23	6.35	-	-	-	-
3,266	2,669	-	-	-	-
47.56	41.27	-	-	-	-
62.98	43.85	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
14	14	13	14	13	6
10	8	8	7	6	3
59,543	58,499	57,542	56,692	55,636	55,147
6.9	7.8	(3.4)	6.5	(1.1)	-

Comparative figures for 2004 and prior years have not been restated to conform to the current financial presentation.

(1) Non-GAAP financial measure. See discussion on page 28.

(2) Resegmentations occurred in 2005 and 2002. Prior years were not restated.

(3) AltaGas purchased 100 percent of the outstanding common shares of AltaGas Utilities Inc. on June 30, 1998. On November 17, 2005 AltaGas spun-out its Natural Gas Distribution segment to AltaGas Utility Group Inc. (Utility Group), of which it holds a 19.6 percent interest.

(4) Distributions declared do not include \$0.54 per unit declared in November 2005 in the form of shares of Utility Group as a result of the spin-out of the Natural Gas Distribution business, or \$0.076 per unit in August 2007, also in the form of shares of Utility Group.

(5) As at December 31.

(6) Fourth quarter average.

(7) Annual average.

(8) Average for fourth quarter except for 1998, which only included December.

(9) Volumes do not include condensate pipeline volumes.

(10) AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

(11) Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

(12) Excludes Inuvik Gas Ltd. and Heritage Gas Limited.

(13) Variance from 20-year average – positive variances are favourable.

Unitholder Information

2007 Distributions per Unit

Declaration Date	Record Date	Payment Date	Total Cash Distribution
January 12, 2007	January 25, 2007	February 15, 2007	\$0.170
February 14, 2007	February 26, 2007	March 15, 2007	\$0.170
February 28, 2007	March 26, 2007	April 16, 2007	\$0.170
April 11, 2007	April 25, 2007	May 15, 2007	\$0.170
May 9, 2007	May 25, 2007	June 15, 2007	\$0.170
June 13, 2007	June 25, 2007	July 16, 2007	\$0.170
July 12, 2007	July 25, 2007	August 15, 2007	\$0.170
August 8, 2007	August 27, 2007	September 17, 2007	\$0.175*
September 12, 2007	September 25, 2007	October 15, 2007	\$0.175
October 12, 2007	October 25, 2007	November 15, 2007	\$0.175
November 7, 2007	November 26, 2007	December 17, 2007	\$0.175
December 12, 2007	December 27, 2007	January 15, 2008	\$0.175
Total 2007 Cash Distribution Declared			\$2.065

* In addition, a special distribution of one AltaGas Utility Group Inc. (Utility Group) common share was issued for every 100 Trust units and exchangeable units held on August 27, 2007. Any Trust unitholder allocated fewer than 50 common shares of Utility Group received cash. The cash value of the distribution was determined to be \$0.076 per unit.

Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP or the plan)

AltaGas Income Trust offers a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for eligible holders of Trust units and limited partnership units that are exchangeable into Trust units (Exchangeable Units).

The plan provides unitholders with a convenient and economical way to maximize their investment in AltaGas by providing the opportunity to:

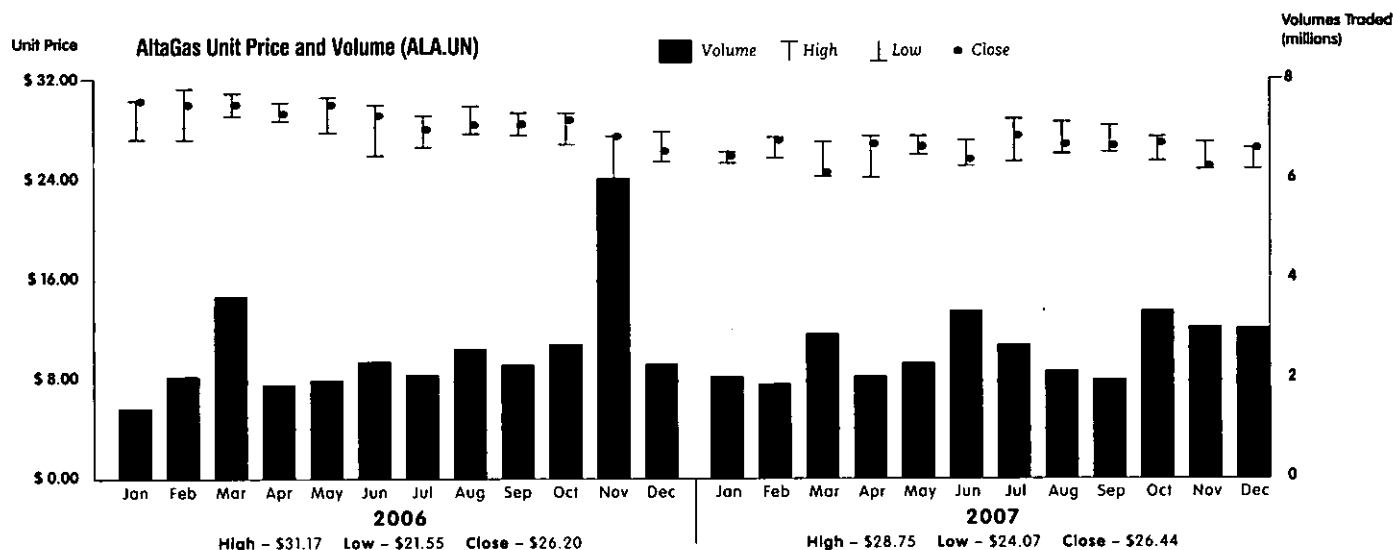
- Reinvest cash distributions into Trust units at a 5 percent discount to the average market price, under the distribution reinvestment component of the plan; or
- Receive a 2 percent premium cash distribution, under the premium distribution component of the plan. AltaGas has suspended the Premium component of the plan. While the Premium component of

the plan is suspended, participants will continue to receive regular cash distributions.

- Eligible unitholders may also make optional trust unit purchases at the weighted average market price.

Registered unitholders who are eligible and wish to participate in the plan must enroll directly with Computershare Trust Company of Canada, while beneficial unitholders should contact their broker, investment dealer, financial institution or other nominee that holds their units, in order to enroll.

Complete details on the DRIP are available on the AltaGas website at www.altagas.ca.



Corporate Information

MANAGEMENT TEAM

David W. Cornhill
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

Richard M. Alexander
PRESIDENT AND CHIEF OPERATING OFFICER

Massimiliano Fantuz
EXECUTIVE VICE PRESIDENT

Deborah S. Stein
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER

David R. Wright
EXECUTIVE VICE PRESIDENT STRATEGY AND CORPORATE DEVELOPMENT

Gregory A. Aarssen
VICE PRESIDENT CORPORATE AFFAIRS

Nancy A. Anderson
VICE PRESIDENT BUSINESS DEVELOPMENT

Jeremy R. Baines
TREASURER

James B. Bracken
SENIOR VICE PRESIDENT MAJOR PROJECTS

Dennis A. Dawson
VICE PRESIDENT GENERAL COUNSEL AND CORPORATE SECRETARY

Michael J. Kilby
DIVISIONAL VICE PRESIDENT GAS SERVICES

Bradley G. H. Mattson
VICE PRESIDENT AND CORPORATE CONTROLLER

Patricia M. Newson
SENIOR VICE PRESIDENT

Jeffrey F. Perry
DIVISIONAL VICE PRESIDENT FIELD GATHERING AND PROCESSING

Marilyn A. Pfaefflin
DIVISIONAL VICE PRESIDENT TRANSMISSION

Kent E. Stout
VICE PRESIDENT CORPORATE RESOURCES

William C. Swan
DIVISIONAL VICE PRESIDENT ENERGY MANAGEMENT

Randy W. Toone
DIVISIONAL VICE PRESIDENT EXTRACTION AND TRANSMISSION

AUDITORS

Ernst & Young LLP
CALGARY, ALBERTA, CANADA

TRANSFER AGENT

Computershare Trust Company of Canada
CALGARY, ALBERTA, CANADA

Toll-free: 800-564-6253

Email: service@computershare.com

Investors are encouraged to contact Computershare for information concerning their security holdings.

STOCK EXCHANGE LISTING

Toronto Stock Exchange: ALA.UN

ANNUAL MEETING

The annual meeting will be held at 3:00 p.m.

MDT on Thursday, April 24, 2008 at

The Metropolitan Centre, Strand/Tivoli Room,
333 – 4th Avenue S.W., Calgary, Alberta.

INVESTOR RELATIONS

For investor relations enquiries, please contact:

Tel: 403-691-7100

Toll-free: 877-691-7199

Fax: 403-691-7150

Email: investor.relations@altagas.ca

DEFINITIONS

Bbls/d barrels per day

Bcf billion cubic feet

bps basis points

GJ gigajoule

GWh gigawatt-hour

Mcf thousand cubic feet

Mmcfd million cubic feet per day

MW megawatt

MWh megawatt-hour

PHOTOGRAPHS

FRONT COVER, LEFT TO RIGHT: EDMONTON EXTRACTION PLANT; ENERCON WIND TURBINE.

PAGE 8, CLOCKWISE: EDMONTON EXTRACTION PLANT; EDMONTON EXTRACTION PLANT; POUCE COUPE GAS PROCESSING PLANT; POUCE COUPE GAS PROCESSING PLANT.

PAGE 10, CLOCKWISE: ENERCON WIND TURBINE; BOSTON BAR RUN-OF-RIVER HYDROELECTRIC FACILITY; COALDALE GAS-FIRED PEAKING PLANT; TRANSALTA CORPORATION SUNDANCE POWER PLANT.

AltaGas

Well connected.

ALTAGAS INCOME TRUST

1700, 355 - 4th Avenue SW

Calgary, Alberta, T2P 0J1

www.altagas.ca

Form 1 Submission - Change in Issued and Outstanding Securities

Office Mail
Mail Processing
Section
MAR 31 2008
Washington, DC
106

Issuer : AltaGas Income Trust
Symbol : ALA.UN
Reporting Period: 02/01/2008 - 02/29/2008

Summary

Issued & Outstanding Opening Balance : 63,424,450 As at : 02/01/2008

Effect on Issued & Outstanding Securities

Employee Trust Unit Option Plan #1 (10%) April 27, 2006	0
DRIP Plan #1 - Trust Units	123,666
DRIP Plan #2 - Exchangeable LP Units	7
Other Issuances and Cancellations	313,868

Issued & Outstanding Closing Balance : 63,861,991

Employee Trust Unit Option Plan #1 (10%) April 27, 2006

Stock Options Outstanding Opening Balance: 1,311,775 As at : 02/01/2008

Effective Date	SAR	Options Granted	Options Exercised	Options Cancelled	SAR Reduction in Reserve
02/01/2008	N	279,250			
Filer's comment Options granted to new employees at an exercise price of \$23.35 expiring February 1, 2018					
02/03/2008	N			1,125	
Filer's comment September 6, 2006 options cancelled due to employee departure					
02/04/2008	N			1,250	
Filer's comment June 5, 2006 options cancelled due to employee departure					
02/04/2008	N			1,500	
Filer's comment September 6, 2006 options cancelled due to employee departure					
02/08/2008	N			1,125	
Filer's comment September 6, 2006 options cancelled due to employee departure					
02/23/2008	N			500	
Filer's comment September 6, 2006 options cancelled due to employee departure					
Totals		279,250	0	5,500	0

Stock Options Outstanding Closing Balance: 1,585,525 As at : 02/29/2008

DRIP Plan #1 - Trust Units

Opening Reserve 2,098,711 As at : 02/01/2008

Effective Date	Securities Listed	Securities Issued
02/15/2008		123,666

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CORPORATE FINANCE

Totals	0	123,666

Closing Reserve:	1,975,045	As at : 02/29/2008

DRIP Plan #2 - Exchangeable LP Units

Opening Reserve	704,294	As at : 02/01/2008

Effective Date	Securities Listed	Securities Issued
02/15/2008		7
Totals	0	7

Closing Reserve:	704,287	As at : 02/29/2008

Other Issuances and Cancellations

Effective Date	Transaction Type	Number of Securities
02/07/2008	Acquisition	9,613
Filer's comment Trust Units issued pursuant to Taylor compulsory take-up		
02/20/2008	Acquisition	44,231
Filer's comment Trust Units issued pursuant to Taylor compulsory take-up		
02/21/2008	Acquisition	250,893
Filer's comment Trust Units issued pursuant to Taylor deemed default		
02/28/2008	Conversion (General)	9,131
Filer's comment Trust Units issued upon conversion of outstanding Taylor debentures		
Totals		313,868

Filed on behalf of the Issuer by:

Name:	Tammy Belsham
Phone:	(403) 691-7517
Email:	tammy.belsham@altagas.ca
Submission Date:	03/05/2008
Last Updated:	03/05/2008



ALTAGAS INCOME TRUST

**NOTICE OF THE ANNUAL MEETING OF UNITHOLDERS
TO BE HELD ON APRIL 24, 2008**

NOTICE IS HEREBY GIVEN that the Annual Meeting (the "**Meeting**") of the holders ("**Unitholders**") of trust units ("**Trust Units**") of AltaGas Income Trust (the "**Trust**") will be held at the Metropolitan Centre, 333 - 4th Avenue S.W., Calgary, Alberta, on Thursday, April 24, 2008, at 3:00 p.m. (Calgary time) for the following purposes:

1. to receive the annual report of the directors of AltaGas General Partner Inc. (the "**General Partner**"), on behalf of the Trust, to the Unitholders and the consolidated financial statements of the Trust for the year ended December 31, 2007 and the auditors' report thereon;
2. to consider the nominees standing for election as directors of the General Partner, to fix the number of directors of the General Partner and to direct Computershare Trust Company of Canada, as trustee of the Trust, to cause the election of the directors of the General Partner;
3. to appoint Ernst & Young LLP as auditors of the Trust and to authorize the directors of the General Partner to fix Ernst & Young LLP's remuneration in that capacity; and
4. to transact such other business as may properly be brought before the Meeting or any adjournment(s) thereof.

Information relating to the matters to be brought before the Meeting is set forth in the Management Information Circular dated March 6, 2008 which accompanies this notice and which is expressly made a part of this notice.

DATED at Calgary, Alberta, as of the 6th day of March, 2008.

**BY ORDER OF THE BOARD OF DIRECTORS
OF ALTAGAS GENERAL PARTNER INC., for
and on behalf of ALTAGAS INCOME TRUST**

"David W. Cornhill"

David W. Cornhill
Chairman and Chief Executive Officer

Unitholders of record at the close of business on February 28, 2008 (the "Record Date") will receive notice of, and be entitled to attend and vote at, the Meeting. No Unitholder who becomes a Unitholder after the Record Date shall be entitled to attend or vote at the Meeting.

A Unitholder who is unable to attend the Meeting in person is requested to complete and sign the enclosed form of proxy and to deliver it by regular mail to Computershare Trust Company of Canada, 100 University Ave., 9th Floor, Toronto, Ontario M5J 2Y1 (or to send it by courier or hand delivery to Computershare Trust Company of Canada's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8). In order to be valid and acted upon at the Meeting, the form of proxy must be received no later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or be deposited with the Chairman of the Meeting prior to its commencement.

Holders of Class B limited partnership units ("LP #1 B Units") in the capital of AltaGas Holding Limited Partnership No. 1 of record at the close of business on the Record Date will be entitled to receive notice of, and to attend and vote at, the Meeting.

Holders of LP #1 B Units who are unable to attend the Meeting in person are requested to complete and sign the enclosed Voting Instruction Form and deliver it by regular mail to Computershare Trust Company of Canada, 100 University Ave., 9th Floor, Toronto, Ontario M5J 2Y1 (or to send it by courier or hand delivery to Computershare Trust Company of Canada's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8). In order to be valid and acted upon at the Meeting, the Voting Instruction Form must be received no later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or be deposited with the Chairman of the Meeting prior to its commencement.



SEC File # 82-34911



9th Floor, 100 University Avenue
Toronto, Ontario M5J 2Y1
www.computershare.com

Security Class

Holder Account Number

Fold

Form of Proxy - Annual Meeting to be held on April 24, 2008

This Form of Proxy is solicited by and on behalf of Management.

Notes to proxy

1. This proxy should be read in conjunction with the accompanying documentation provided by Management.
2. Every holder has the right to appoint some other person or company of their choice, who need not be a holder, to attend and act on their behalf at the meeting. If you wish to appoint a person or company other than the persons whose names are printed herein, please insert the name of your chosen proxyholder in the space provided (see reverse).
3. If the securities are registered in the name of more than one owner (for example, joint ownership, trustees, executors, etc.), then all those registered should sign this proxy. If you are voting on behalf of a corporation or another individual you may be required to provide documentation evidencing your power to sign this proxy with signing capacity stated.
4. This proxy should be signed in the exact manner as the name appears on the proxy.
5. If this proxy is not dated, it will be deemed to bear the date on which it is mailed by Management to the holder.
6. The securities represented by this proxy will be voted as directed by the holder, however, if such a direction is not made in respect of any matter, this proxy will be voted as recommended by Management.
7. The securities represented by this proxy will be voted or withheld from voting, in accordance with the instructions of the holder, on any ballot that may be called for and, if the holder has specified a choice with respect to any matter to be acted on, the securities will be voted accordingly.
8. This proxy confers discretionary authority in respect of amendments to matters identified in the Notice of Meeting or other matters that may properly come before the meeting.

Fold

Proxies submitted must be received by 3:00 p.m., Calgary time, on Tuesday, April 22, 2008.

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SEC File # 82-34911

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Appointment of Proxyholder

I/We hereby appoint: David W. Cornhill, Chairman and Chief Executive Officer of AltaGas General Partner Inc. (the "General Partner"), of the City of Calgary, in the Province of Alberta, or failing him, Richard M. Alexander, President and Chief Operating Officer of the General Partner, of the City of Calgary, in the Province of Alberta,

OR

I/We hereby appoint the person whose name I/we have printed adjacent to this statement (and by so printing such name, I/we confirm that I/we do not appoint either Management Nominee proxyholder),

as my/our proxyholder with full power of substitution and to vote in accordance with the following direction (or if no directions have been given, as the proxyholder sees fit) and all other matters that may properly come before the Annual Meeting of AltaGas Income Trust (the "Trust") to be held at the Metropolitan Conference Centre, 333 - 4th Avenue SW, Calgary, Alberta on April 24, 2008 at 3:00 p.m. and at any adjournment thereof.

VOTING RECOMMENDATIONS ARE INDICATED BY **HIGHLIGHTED TEXT** OVER THE BOXES.

1. Election of Directors

Passing an ordinary resolution to fix the number of directors of the General Partner to be elected at eight (8), and to direct Computershare Trust Company of Canada, as trustee of the Trust, to cause the election of those nominees described in the Management Information Circular of the Trust dated March 6, 2008 (the "Information Circular") as directors of the General Partner.

Vote FOR or WITHHOLD for all nominees proposed by Management

For **Withhold**

☐ ☐
2. Appointment of Auditors

Passing an ordinary resolution to appoint Ernst & Young LLP as auditors of the Trust and to authorize the directors of the General Partner to fix Ernst & Young LLP's remuneration in that capacity.

For **Withhold**

☐ ☐
3. Other Business

At the discretion of the said proxyholders, upon any amendment or variation of the above matters or any other matter that may be properly brought before the Meeting or any adjournment thereof in such manner as such proxy, in such proxyholder's sole judgment, may determine.

Authorized Signature(s) - This section must be completed for your instructions to be executed.

I/We authorize you to act in accordance with my/our instructions set out above. I/We hereby revoke any proxy previously given with respect to the Meeting. If no voting instructions are indicated above, this Proxy will be voted as recommended by Management.

Signature(s)

Date

ECM / 00 / YY

Interim Financial Statements

Mark this box if you would like to receive interim financial statements and accompanying Management's Discussion and Analysis by mail.

☐
Annual Report

Mark this box if you would NOT like to receive the Annual Report and accompanying Management's Discussion and Analysis by mail.

☐

If you are not mailing back your proxy, you may register online to receive the above financial report(s) by mail at www.computershare.com/maillinglist.

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SEC Mail
Mail Processing
Section
MAR 31 2008
Washington, DC
100

AltaGas

Well connected. □

ALTAGAS INCOME TRUST

Notice of Meeting
and
Management Information Circular
for the
ANNUAL MEETING OF UNITHOLDERS
to be held on April 24, 2008

RECEIVED
2008 APR -2 A 7:53
OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Dated March 6, 2008



ALTAGAS INCOME TRUST

March 6, 2008

Dear Unitholder:

Please accept this as my personal invitation for you to attend the Annual Meeting of the unitholders of AltaGas Income Trust (the "Trust") to be held on Thursday, April 24, 2008 at 3:00 p.m. (Calgary time) at the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta.

The Notice of Meeting and Management Information Circular attached to this letter provide details as to the formal business items to be considered at the meeting. In addition to the formal business items, I will be presenting an overview of the Trust's results for the financial year ended December 31, 2007 and discussing the Trust's strategy for the future. The meeting is also an opportunity for you to meet the board of directors of AltaGas General Partner Inc. and the senior executives of AltaGas Ltd.

If you are unable to attend the meeting in person, I encourage you to complete the enclosed form of proxy or, if applicable, voting instruction form and return it within the time frames indicated, so that your vote is counted at the meeting. If you are unable to attend the meeting in person, you may listen to a live webcast, which will be available on the Trust's website at www.altagas.ca commencing at 3:00 p.m. (Calgary time) on Thursday, April 24, 2008.

Information concerning the Trust's consolidated financial and operational performance for the financial year ended December 31, 2007 is presented in the 2007 Annual Report. Further information is available on the Trust's website at www.altagas.ca.

I appreciate your continued support of the Trust, and look forward to seeing you at the meeting.

Yours truly,

**ALTAGAS INCOME TRUST, by its
administrator, ALTAGAS LTD.**

"David W. Cornhill"

David W. Cornhill
Chairman and Chief Executive Officer



ALTAGAS INCOME TRUST

NOTICE OF THE ANNUAL MEETING OF UNITHOLDERS TO BE HELD ON APRIL 24, 2008

NOTICE IS HEREBY GIVEN that the Annual Meeting (the "**Meeting**") of the holders ("**Unitholders**") of trust units ("**Trust Units**") of AltaGas Income Trust (the "**Trust**") will be held at the Metropolitan Centre, 333 - 4th Avenue S.W., Calgary, Alberta, on Thursday, April 24, 2008, at 3:00 p.m. (Calgary time) for the following purposes:

1. to receive the annual report of the directors of AltaGas General Partner Inc. (the "**General Partner**"), on behalf of the Trust, to the Unitholders and the consolidated financial statements of the Trust for the year ended December 31, 2007 and the auditors' report thereon;
2. to consider the nominees standing for election as directors of the General Partner, to fix the number of directors of the General Partner and to direct Computershare Trust Company of Canada, as trustee of the Trust, to cause the election of the directors of the General Partner;
3. to appoint Ernst & Young LLP as auditors of the Trust and to authorize the directors of the General Partner to fix Ernst & Young LLP's remuneration in that capacity; and
4. to transact such other business as may properly be brought before the Meeting or any adjournment(s) thereof.

Information relating to the matters to be brought before the Meeting is set forth in the Management Information Circular dated March 6, 2008 which accompanies this notice and which is expressly made a part of this notice.

DATED at Calgary, Alberta, as of the 6th day of March, 2008.

**BY ORDER OF THE BOARD OF DIRECTORS
OF ALTAGAS GENERAL PARTNER INC., for
and on behalf of ALTAGAS INCOME TRUST**

"David W. Cornhill"

David W. Cornhill
Chairman and Chief Executive Officer

Unitholders of record at the close of business on February 28, 2008 (the "Record Date") will receive notice of, and be entitled to attend and vote at, the Meeting. No Unitholder who becomes a Unitholder after the Record Date shall be entitled to attend or vote at the Meeting.

A Unitholder who is unable to attend the Meeting in person is requested to complete and sign the enclosed form of proxy and to deliver it by regular mail to Computershare Trust Company of Canada, 100 University Ave., 9th Floor, Toronto, Ontario M5J 2Y1 (or to send it by courier or hand delivery to Computershare Trust Company of Canada's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8). In order to be valid and acted upon at the Meeting, the form of proxy must be received no later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or be deposited with the Chairman of the Meeting prior to its commencement.

Holders of Class B limited partnership units ("LP #1 B Units") in the capital of AltaGas Holding Limited Partnership No. 1 of record at the close of business on the Record Date will be entitled to receive notice of, and to attend and vote at, the Meeting.

Holders of LP #1 B Units who are unable to attend the Meeting in person are requested to complete and sign the enclosed Voting Instruction Form and deliver it by regular mail to Computershare Trust Company of Canada, 100 University Ave., 9th Floor, Toronto, Ontario M5J 2Y1 (or to send it by courier or hand delivery to Computershare Trust Company of Canada's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8). In order to be valid and acted upon at the Meeting, the Voting Instruction Form must be received no later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or be deposited with the Chairman of the Meeting prior to its commencement.

TABLE OF CONTENTS

GENERAL PROXY INFORMATION.....	1
Solicitation of Proxies	1
Appointment of Proxy	1
Revocation of Proxy	2
Exercise of Discretion by Proxy	2
Notice to Beneficial Holders of Trust Units	3
VOTING SECURITIES AND PRINCIPAL HOLDERS THEREOF	3
Trust Units	3
Exchangeable Units	4
PRINCIPAL HOLDERS OF TRUST UNITS AND EXCHANGEABLE UNITS	4
QUORUM FOR MEETING	4
APPROVAL REQUIREMENTS	4
MATTERS TO BE CONSIDERED AT THE MEETING	4
Financial Statements	4
Election of Directors	4
Appointment of Auditors	8
INTEREST OF CERTAIN PERSONS OR COMPANIES IN MATTERS TO BE ACTED UPON	9
INTEREST OF INFORMED PERSONS IN MATERIAL TRANSACTIONS	9
INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS	9
TRUST GOVERNANCE	10
General	10
Board Committees	10
REPORT ON EMPLOYEE AND EXECUTIVE COMPENSATION	12
The Human Resources and Compensation Committee	12
Compensation Policy	12
Chief Executive Officer Compensation	15
PERFORMANCE GRAPH	16
EXECUTIVE COMPENSATION	17
Employment Agreements	19
Retention of Employees on Change of Control	21
Trust Unit Option Grants and MTIP Grants	21
Trust Unit Option Exercises and Financial Year End Values	22
Pension Plans	23
Long Term Incentive Plans	23
Other Compensation	23
Trust Unit Ownership Guideline for Officers	24
COMPENSATION OF DIRECTORS	24
Cash Compensation	24
Equity Compensation	25
Total Compensation	27
Trust Unit Ownership Guideline for Directors	27
Directors and Officers Liability Insurance	28
SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS	28
OTHER MATTERS	29
SCHEDULE A – STATEMENT OF GENERAL PARTNER’S GOVERNANCE PRACTICES	A-1



ALTAGAS INCOME TRUST

MANAGEMENT INFORMATION CIRCULAR

GENERAL PROXY INFORMATION

Solicitation of Proxies

This management information circular ("Information Circular") is furnished in connection with the solicitation of proxies on behalf of Computershare Trust Company of Canada (the "Trustee") in its capacity as trustee of AltaGas Income Trust (the "Trust") by AltaGas General Partner Inc. (the "General Partner"), the delegate of the Trustee, for use at the Annual Meeting (the "Meeting") of the holders ("Unitholders") of trust units ("Trust Units") of the Trust to be held at the Metropolitan Centre, 333 - 4th Avenue S.W., Calgary, Alberta, on Thursday, April 24, 2008, at 3:00 p.m. (Calgary time) and at any adjournment(s) thereof for the purposes set out in the accompanying notice of meeting (the "Notice of Meeting"). Although it is expected that the solicitation of proxies will be primarily by mail, proxies may also be solicited personally or by telephone, facsimile or e-mail by regular employees of AltaGas Ltd. ("AltaGas"). Pursuant to National Instrument 54-101 *Communication with Beneficial Owners of Securities of a Reporting Issuer*, arrangements have been made with clearing agencies, brokerage houses and other financial intermediaries to forward proxy solicitation material to the beneficial owners of the Trust Units and the Exchangeable Units (as hereinafter defined). The cost of any such solicitation will be borne by the Trust. Information contained herein is given as of the date hereof unless otherwise specifically stated.

The Voting and Exchange Trustee (as hereinafter defined) has sent copies of the Notice of Meeting to the holders of the Exchangeable Units, together with copies of this Information Circular and the related meeting materials and a statement as to the manner in which those holders may instruct the Voting and Exchange Trustee to exercise the votes attaching to the Special Voting Unit (as hereinafter defined) entitled. Where applicable, "Unitholders" herein means the holders of Trust Units and the Voting Exchange Trustee, as holder of the Special Voting Unit.

For the purpose of this Information Circular, unless the context otherwise requires, capitalized terms shall have the meanings ascribed to those terms in the declaration of trust dated as of March 26, 2004, between the initial Unitholder and the Trustee, as amended by a first supplemental indenture dated as of April 30, 2004 (the declaration of trust, as amended, being referred to herein as the "**Declaration of Trust**"). A copy of the Declaration of Trust is available to Unitholders from the head office of AltaGas on demand and upon payment of reasonable reproduction costs or alternatively under the Trust's profile at www.sedar.com.

Appointment of Proxy

Unitholders who wish to vote their Trust Units should complete, sign and deliver by regular mail the enclosed form of proxy to the Trust's registrar and transfer agent, Computershare Trust Company of Canada ("**Computershare**"), 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1 Attention: Proxy Department (or send it by courier or hand delivery to Computershare's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta T2P 3S8). In order to be valid and acted upon at the Meeting, a form of proxy must be received no later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or be deposited with the Chairman of the Meeting prior to the commencement thereof. By a resolution of the board of directors of the General Partner (the "**board of directors**"), the record date for the Meeting has been established as the close of business on February 28, 2008 (the "**Record Date**"). Only Unitholders of record as at the Record Date will receive notice of, and be entitled to attend and vote at, the Meeting. A Unitholder of record on the Record Date will be entitled to vote those Trust Units included in the list of Unitholders entitled to vote at the Meeting prepared as at the Record Date, even though the Unitholder may subsequently dispose of his or her Trust Units. No Unitholder who has become a Unitholder after the Record Date shall be entitled to attend or vote at the Meeting or any adjournment(s) thereof.

The document appointing a proxy shall be in writing and shall be executed by the Unitholder or his attorney authorized in writing or, if the Unitholder is a corporation, under its corporate seal or by an officer or attorney thereof duly authorized.

A Unitholder submitting a form of proxy has the right to appoint a person to represent him or her at the Meeting (who need not be a Unitholder) other than the persons designated in the form of proxy furnished on behalf of the Trustee by the General Partner. To exercise that right, the name of the Unitholder's appointee should be legibly printed in the blank space provided. In addition, the Unitholder should notify the appointee of his or her appointment, obtain his or her consent to act as appointee and instruct him or her on how the Unitholder's Trust Units are to be voted.

Holders of Exchangeable Units who wish to vote at the Meeting should complete and deliver their voting instructions in the manner contemplated in the Voting Instruction Form provided by the Voting and Exchange Trustee in conjunction with this Information Circular. Those instructions may be delivered by regular mail to Computershare, 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1 Attention: Proxy Department (or sent by courier or hand delivery to Computershare's Calgary office at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8). In order to be valid those instructions must be received by the Voting and Exchange Trustee not later than 3:00 p.m. (Calgary time) on the second business day before the date of the Meeting or any adjournment(s) thereof or deposited with the Chairman of the Meeting prior to the commencement thereof.

Only holders of Exchangeable Units of record on the Record Date are entitled to receive notice of, and to direct the Voting and Exchange Trustee regarding voting at, the Meeting. Holders of Exchangeable Units of record on the Record Date will be entitled to direct the voting of the corresponding votes attached to the Special Voting Unit to the extent of the rights attached to the Exchangeable Units included in the list(s) of those holders prepared as at the Record Date, even though any such holder may subsequently dispose of those Exchangeable Units.

Revocation of Proxy

A Unitholder who has submitted a form of proxy as directed hereunder may revoke it at any time prior to the exercise thereof. If a person who has given a proxy attends personally at the Meeting at which that proxy is to be voted, that person may revoke the proxy and vote in person. In addition to the revocation in any other manner permitted by law, a proxy may be revoked by instrument in writing executed by the Unitholder or his attorney or authorized agent and deposited either at the office of Computershare at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8 at any time up to 3:00 p.m. (Calgary time) on the last business day before the date of the Meeting, or any adjournment(s) thereof, or with the Chairman of the Meeting on the day of the Meeting or any adjournment(s) thereof, in either case prior to its commencement, and upon either of those deposits, the proxy is revoked.

A holder of Exchangeable Units who has submitted instructions to the Voting and Exchange Trustee with respect to the exercise of votes attached to the Special Voting Unit may revoke those instructions at any time prior to the exercise thereof. In addition to the revocation in any other manner permitted by law, voting instructions provided to the Voting and Exchange Trustee may be revoked by instrument in writing executed by the holder of the Exchangeable Units or his attorney or authorized agent and deposited with the Voting and Exchange Trustee at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8 at any time up to 3:00 p.m. (Calgary time) on the last business day before the date of the Meeting, or any adjournment(s) thereof, or with the Chairman of the Meeting on the day of the Meeting or any adjournment(s) thereof, in either case prior to its commencement, and upon either of those deposits, the voting instructions are revoked.

Exercise of Discretion by Proxy

The Trust Units represented by proxy will be voted on any ballot at the Meeting and, where the Unitholder specifies a choice with respect to any matter to be voted upon, those Trust Units shall be voted on or shall be withheld from voting on any ballot in accordance with the specification so made. **In the absence of any such specification, those Trust Units will be voted in favour of the proposed resolutions contained herein. The persons appointed under the form of proxy furnished on behalf of the Trustee by the General Partner are conferred with discretionary authority with respect to amendments or variations of those matters specified in the proxy and Notice of Meeting and as to other matters which may be properly brought before the Meeting. At the time of mailing of this Information Circular, neither the Trustee nor the General Partner knew of any such amendment, variation or other matter.**

Each holder of an Exchangeable Unit on the Record Date is entitled to direct the Voting and Exchange Trustee to exercise the part of the Equivalent Vote Amount (as hereinafter defined) attached to the Special Voting Unit corresponding to the Exchangeable Units held by that holder. Alternatively, that holder is entitled to direct the Voting and Exchange Trustee to give a proxy to that holder or his designee to personally exercise those votes or to a designated agent or other representative of the General Partner. **The Voting and Exchange Trustee will exercise each vote attached to the Special Voting Unit only as directed by the holder of an Exchangeable Unit and, in the absence of instructions from a holder as to voting, will not exercise those votes.**

Notice to Beneficial Holders of Trust Units

The information set forth in this section is of significant importance to many Unitholders, as a substantial number of the Unitholders do not hold Trust Units in their own name. Unitholders who do not hold their Trust Units in their own name (referred to herein as "**Beneficial Unitholders**") should note that only proxies deposited by Unitholders whose names appear on the records of the Trust as the registered holders of Trust Units can be recognized and acted upon at the Meeting or any adjournment(s) thereof. If Trust Units are listed in an account statement provided to a Unitholder by a broker, then in almost all cases those Trust Units will not be registered in the Unitholder's name on the records of the Trust. Those Trust Units will more likely be registered under the name of the Unitholder's broker or an agent of that broker. In Canada, the vast majority of those Trust Units are registered under the name of CDS & Co. (the registration name for CDS Clearing and Depository Services Inc., which acts as nominee for many Canadian brokerage firms). Trust Units held by brokers or their nominees can only be voted (for or against resolutions) upon the instructions of the Beneficial Unitholder. Without specific instructions, the broker/nominees are prohibited from voting Trust Units for their clients. The Trust does not know for whose benefit the Trust Units registered in the name of CDS & Co., a broker or another nominee, are held.

Applicable regulatory policy requires intermediaries (such as brokers or other nominees) to seek voting instructions from Beneficial Unitholders in advance of Unitholders' meetings. Every intermediary/broker has its own mailing procedures and provides its own return instructions, which should be carefully followed by Beneficial Unitholders in order to ensure that their Trust Units are voted at the Meeting or any adjournment(s) thereof. Often, the form of proxy supplied to a Beneficial Unitholder by its broker is identical to the form of proxy provided to registered Unitholders; however, its purpose is limited to instructing the registered Unitholder how to vote on behalf of the Beneficial Unitholder. Beneficial Unitholders who wish to appear in person and vote at the Meeting should be appointed as their own representatives at the Meeting in accordance with the directions of their intermediaries. The majority of brokers now delegate responsibility for obtaining instructions from clients to Broadridge Financial Solutions, Inc. ("**Broadridge**"). Broadridge typically mails a scannable voting instruction form in lieu of the form of proxy. The Beneficial Unitholder is requested to complete and return the voting instruction form to Broadridge by mail or facsimile. Alternatively, the Beneficial Unitholder can call a toll-free telephone number to vote the Trust Units held by the Beneficial Unitholder or access Broadridge's dedicated voting website at www.proxyvotecanada.com to deliver the Beneficial Unitholder's voting instructions. Broadridge then tabulates the results of all instructions received and provides appropriate instructions respecting the voting of Trust Units to be represented at the Meeting or any adjournment(s) thereof. A Beneficial Unitholder receiving a voting instruction form cannot use that voting instruction form to vote Trust Units directly at the Meeting or any adjournment(s) thereof as the voting instruction form must be returned as directed by Broadridge well in advance of the Meeting or any adjournment(s) thereof, as the case may be, in order to have the Trust Units voted.

VOTING SECURITIES AND PRINCIPAL HOLDERS THEREOF

Trust Units

The Trust is authorized to issue an unlimited number of Trust Units. As at the Record Date, 63,861,991 Trust Units were issued and outstanding. Unitholders of record are entitled to notice of and to attend at the Meeting, in person or by proxy, and to one vote per Trust Unit held on any ballot thereat. All votes on matters to be brought before the Meeting that require approval by a special resolution shall be conducted by a poll.

When any Trust Unit is held jointly by several persons, any one of them may vote at the Meeting in person or by proxy in respect of such Trust Unit, but if more than one of them shall be present at the Meeting in person or by proxy, and such joint owners or their proxies so present disagree as to any vote to be cast, such vote purporting to be executed by or on behalf of a Unitholder shall be deemed valid unless challenged at or prior to its exercise, and the burden of proving invalidity shall rest on the challenger.

Exchangeable Units

In accordance with a Voting and Exchange Trust Agreement dated May 1, 2004 (the "**Voting and Exchange Trust Agreement**") among the Trust, AltaGas Holding Limited Partnership No. 1 ("**AltaGas LP #1**"), AltaGas Holding Limited Partnership No. 2 ("**AltaGas LP #2**") and Computershare Trust Company of Canada, in its capacity as voting and exchange trustee (the "**Voting and Exchange Trustee**"), the Trust issued a special voting unit (the "**Special Voting Unit**") to the Voting and Exchange Trustee for the benefit of the holders (other than the Trust and its affiliates) of the Class B limited partnership units of AltaGas LP #1 (the "**LP #1 B Units**") and the Class B limited partnership units of AltaGas LP #2 (the "**LP #2 B Units**") and together with the LP #1 B Units referred to collectively as the "**Exchangeable Units**"). The Special Voting Unit carries a number of votes exercisable at the Meeting equal to the product of the number of Exchangeable Units outstanding on the Record Date multiplied by the number of votes to which a holder of one Trust Unit is entitled (the "**Equivalent Vote Amount**").

As at the Record Date, AltaGas LP #1 had 2,183,063 issued and outstanding LP #1 B Units exchangeable in the aggregate into 2,183,063 Trust Units. As at the Record Date, AltaGas LP #2 had no issued and outstanding LP #2 B Units.

PRINCIPAL HOLDERS OF TRUST UNITS AND EXCHANGEABLE UNITS

To the best of the knowledge of the board of directors and the executive officers of AltaGas, no person or company beneficially owns, directly or indirectly, or controls or directs, Trust Units and Exchangeable Units carrying in aggregate 10 percent or more of the votes attached to all of the issued and outstanding Trust Units and the Special Voting Unit.

QUORUM FOR MEETING

At the Meeting, a quorum shall consist of two or more individuals present in person either holding personally or representing as proxies not less in aggregate than 5 percent of the votes attached to all issued and outstanding Trust Units and the Special Voting Unit. If a quorum is not present at the Meeting within 30 minutes after the time fixed for the holding of the Meeting, the Meeting shall stand adjourned to such day being not less than seven days later and to such place and time as may be determined by the Chairman of the Meeting. At that adjourned Meeting, the Unitholders present either personally or by proxy shall constitute a quorum.

APPROVAL REQUIREMENTS

The specific resolutions that Unitholders will be asked to approve at the Meeting include resolutions regarding the election of the directors of the General Partner and the appointment of the auditors of the Trust.

In order to be effective, the foregoing resolutions require the approval of more than 50 percent of the votes cast in respect of those resolutions by or on behalf of Unitholders present in person or represented by proxy at the Meeting.

MATTERS TO BE CONSIDERED AT THE MEETING

Financial Statements

At the Meeting, the consolidated financial statements of the Trust for the year ended December 31, 2007 and the auditors' report thereon will be presented. These consolidated financial statements and Management's Discussion & Analysis relating thereto are included in the 2007 Annual Report of the Trust.

Election of Directors

The board of directors currently consists of eight members, all of whom are elected annually. It is proposed that the number of directors of the General Partner to be elected be fixed at eight and that the Trustee be directed to cause the persons named below to be elected as directors of the General Partner.

The following eight nominees are proposed by the General Partner on behalf of the Trustee as the nominees for election as directors of the General Partner to serve until the next annual meeting of Unitholders or until their successors are duly elected or appointed:

David W. Cornhill
Allan L. Edgeworth
Denis C. Fonteyne
Daryl H. Gilbert
Robert B. Hodgins
Myron F. Kanik
David F. Mackie
M. Neil McCrank

If any vacancies occur in the slate of those nominees because any nominee is unable to serve or will not serve, the discretionary authority conferred by the proxies will be exercised to grant approval to the Trustee to vote for the election of any other person or persons nominated by the General Partner on behalf of the Trustee. The names of the nominees for election as directors, their municipalities of residence, age, present principal occupations, and where required, their principal occupations during the last five years, whether they are independent, the year in which each became a director of the General Partner and numbers of Trust Units and Exchangeable Units, if any, beneficially owned or over which control or direction is exercised by those persons, as at December 31, 2007, are as follows:

	Name of Proposed Nominee ⁽¹⁾	Background	Board Attendance; Committee Membership and Attendance; and Outside Directorships
	David W. Cornhill Calgary, Alberta, Canada Age⁽²⁾: 54 Chairman and Chief Executive Officer of the General Partner and AltaGas Non-Independent Director⁽³⁾ Director since May 1, 2004 Director of AltaGas Services Inc. from March 28, 1994 to April 30, 2004 Ownership: Trust Units: 298,990 Exchangeable Units: 692,742 Total Equivalent Trust Units: 991,732 Trust Unit Options: Nil RUs: 3,000 PUs: 118,085	David Cornhill is Chairman and Chief Executive Officer of AltaGas and the General Partner. Mr. Cornhill is a founding member of AltaGas Services Inc., predecessor to the Trust. He has served as Chairman and Chief Executive Officer since AltaGas Services Inc.'s inception on April 1, 1994 and was appointed as a Director of the General Partner on May 1, 2004. Prior to forming AltaGas Services Inc., Mr. Cornhill served in the capacities of Vice President, Finance and Administration, and Treasurer at Alberta and Southern Gas Co. Ltd. from 1991 to 1993 and as President and Chief Executive Officer until March 31, 1994. Mr. Cornhill brings to the board of directors extensive oil and gas expertise in the natural gas processing and transportation industries.	Attendance: Board (Chair) 12/12 Environment, Occupational Health and Safety 3/3 Current Public Board Memberships: AltaGas Utility Group Inc.

	Name of Proposed Nominee ⁽¹⁾	Background	Board Attendance; Committee Membership and Attendance; and Outside Directorships
	Allan L. Edgeworth Calgary, Alberta, Canada Age⁽²⁾: 57 Independent Director Director since March 2, 2005 Ownership: Trust Units: 3,000 Exchangeable Units: Nil Total Equivalent Trust Units: 3,000 Trust Unit Options: 35,000 RUs: 1,500 PUs: Nil	Allan Edgeworth has been the President of ALE Energy Inc. since January 2005. Mr. Edgeworth was the President and CEO of Alliance Pipeline Ltd. from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline Ltd. in 1998 as Executive Vice President and Chief Operating Officer. Prior to that, Mr. Edgeworth spent almost 20 years with Westcoast Energy Inc. where he held various positions including President Pipeline Division and Senior Vice President of Regulatory Affairs.	Attendance: Board 12/12 Audit 6/6 Environment, Occupational Health and Safety 3/3 Current Public Board Memberships: Emera Inc. Pembina Pipeline Corporation
	Denis C. Fonteyne Calgary, Alberta, Canada Age⁽²⁾: 72 Independent Director Director since May 1, 2004 Director of AltaGas Services Inc. from September 1, 1998 to April 30, 2004 Ownership: Trust Units: 21,406 Exchangeable Units: 14,894 Total Equivalent Trust Units: 36,300 Trust Unit Options: 15,000 RUs: 1,500 PUs: Nil	Denis Fonteyne has been a natural gas industry consultant since 1997 and brings over 40 years of industry experience to the board of directors. Mr. Fonteyne has held a number of senior executive positions in the oil and gas industry, most recently as Executive Vice-President with CanStates Gas Marketing Ltd.	Attendance: Board 12/12 Human Resources and Compensation 4/4 Environment, Occupational Health and Safety 3/3 (Chair) Current Public Board Memberships: Mr. Fonteyne is not a member of any other public boards.
	Daryl H. Gilbert⁽⁴⁾ Calgary, Alberta, Canada Age⁽²⁾: 56 Independent Director Director since May 1, 2004 Director of AltaGas Services Inc. from May 4, 2000 to April 30, 2004 Ownership: Trust Units: 900 Exchangeable Units: Nil Total Equivalent Trust Units: 900 Trust Unit Options: 15,000 RUs: 1,500 PUs: Nil	Daryl Gilbert has been an independent businessman since January 2005. Prior to that, Mr. Gilbert was President and Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., an engineering consulting firm.	Attendance: Board 11/12 Audit 6/6 Human Resources and Compensation 2/4 Current Public Board Memberships: Crocotta Energy Inc. Falcon Oil & Gas Ltd. Global Direct, inc. Kereco Energy Ltd. MGM Energy Corp. Nexstar Energy Ltd. Penn West Petroleum Ltd. Qwest Energy Corp. (and related entities) Qwest Investment Management Corp. (and related entities) Seaview Energy Inc. Zedi Inc.

	Name of Proposed Nominee ⁽¹⁾	Background	Board Attendance; Committee Membership and Attendance; and Outside Directorships
	Robert B. Hodgins Calgary, Alberta, Canada Age ⁽²⁾ : 56 Independent Director Director since March 2, 2005 Ownership: Trust Units: 2,000 Exchangeable Units: Nil Total Equivalent Trust Units: 2,000 Trust Unit Options: 35,000 RUs: 1,500 PUs: Nil	Robert Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Corporation from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited from 1998 to 2002 and was Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998.	Attendance: Board 12/12 Audit (Chair) 6/6 Governance 4/4 Current Public Board Memberships: Enerflex Systems Ltd. EnerMark Inc. Fairbome Energy Ltd. MGM Energy Corp.
	Myron F. Kanik Calgary, Alberta, Canada Age ⁽²⁾ : 67 Lead Director Independent Director Director since May 1, 2004 Director of AltaGas Services Inc. from June 1, 2001 to April 30, 2004 Ownership: Trust Units: 28,329 Exchangeable Units: 15,631 Total Equivalent Trust Units: 43,960 Trust Unit Options: 15,000 RUs: 1,500 PUs: Nil	Myron Kanik is the Lead Director and has been the President of Kanik and Associates Ltd., an energy industry consulting company, since 1999. Mr. Kanik has extensive natural gas industry experience, which includes serving as Deputy Minister for the Alberta Department of Energy and as President of the Canadian Energy Pipelines Association. He currently consults to the energy industry.	Attendance: Board 12/12 Governance (Chair) 4/4 Human Resources and Compensation (Chair) 4/4 Current Public Board Memberships: Pembina Pipeline Corporation
	David F. Mackie Houston, Texas, U.S. Age ⁽²⁾ : 70 Independent Director Director since May 1, 2004 Director of AltaGas Services Inc. from January 12, 1995 to April 30, 2004 Ownership: Trust Units: 1,055,216 Exchangeable Units: Nil Total Equivalent Trust Units: 1,055,216 Trust Unit Options: 15,000 RUs: 1,500 PUs: Nil	David Mackie is a U.S.-based natural gas industry consultant and venture capital investor. Mr. Mackie brings a broad range of experience to the board of directors, having spent more than 32 years in various executive capacities, primarily with El Paso Natural Gas Co. and Transco Energy Co. He also has extensive consulting experience with many senior energy companies and the Maritimes and Northeast Pipeline Project.	Attendance: Board 12/12 Governance 4/4 Human Resources and Compensation 4/4 Current Public Board Memberships: Mr. Mackie is not a member of any other public boards.

	Name of Proposed Nominee ⁽¹⁾	Background	Board Attendance; Committee Membership and Attendance; and Outside Directorships
	M. Neil McCrank, Q.C., P.Eng. Calgary, Alberta, Canada Age⁽²⁾: 64 Independent Director Director since December 10, 2007 Ownership: Trust Units: 0 Exchangeable Units: 0 Total Equivalent Trust Units: 0 Trust Unit Options: 20,000 RUs: 750 PU: Nil	Mr. McCrank has been consulting to industry and government on energy regulatory matters since April 2007. Mr. McCrank was Chairman of the Alberta Energy and Utilities Board from 1998 until his retirement on March 31, 2007. Prior to joining the AEUB, Mr. McCrank, a barrister and solicitor, worked with the Alberta Attorney General starting in 1979, serving as Special Prosecutor, Assistant Deputy Minister for the Criminal Justice Division, Deputy Attorney General and Deputy Minister for the Alberta Department of Justice. Prior to his public service career in Alberta, Mr. McCrank worked with the Province of Ontario and spent several years with a private law firm in Toronto. Mr. McCrank became a member of the Law Society of Upper Canada in 1971, the Law Society of Alberta in 1980, and the Association of Professional Engineers, Geologists and Geophysicists of Alberta in 2004.	Attendance⁽³⁾: Board: 1/1 Current Public Board Memberships: Mr. McCrank is not a member of any other public boards.

Notes:

- (1) At December 31, 2007 the nominees for directors of the General Partner collectively held approximately 3.8 percent of the total issued and outstanding Trust Units. The information as to the Trust Units and Exchangeable Units owned includes both Trust Units beneficially owned, directly or indirectly, and Trust Units and Exchangeable Units over which control or direction is exercised, and has been furnished by each of the nominees as of December 31, 2007.
- (2) The Trust has approved a retirement policy for directors pursuant to which the directors agree to retire from the board of directors at age 75.
- (3) Mr. David Cornhill, as Chief Executive Officer of AltaGas General Partner Inc. and a member of management, is not considered independent.
- (4) Mr. Daryl H. Gilbert, a director of the General Partner, is also a director of Globel Direct, inc. ("Globel"). Globel was the subject of a cease trade order issued by the Alberta Securities Commission on November 22, 2002 and the British Columbia Securities Commission on November 20, 2002 because Globel had not filed its Annual Financial Statements for its fiscal year ending May 31, 2002 and its Interim Financial Statements for its first quarter ended August 31, 2002 prior to the prescribed filing deadlines. Globel filed the Annual Financial Statements and Interim Financial Statements and the cease trade orders were removed by the commissions on December 20, 2002 and December 23, 2002, respectively. On June 12, 2007, Globel was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies' Creditors Arrangement Act*. Such protection expired on December 7, 2007, the monitor was discharged on December 12, 2007 and a receiver/manager was appointed.
- (5) Mr. McCrank was appointed to the board of directors on December 10, 2007. One board of directors meeting and no committee meetings took place subsequent to Mr. McCrank's appointment.

Appointment of Auditors

Unless it is specified in a proxy that the Unitholder withholds approval for the Trustee to cause the appointment of Ernst & Young LLP ("E&Y") as auditors of the Trust, the persons named in the enclosed form of proxy intend to grant approval to the General Partner on behalf of the Trustee to cause the appointment of E&Y as

auditors of the Trust, to hold office until the next annual meeting of Unitholders following the Meeting, with remuneration to be determined by the General Partner. Fees paid to E&Y during 2006 and 2007 were as follows:

Category of External Auditor Service Fee	2007	2006
Audit Fees	\$676,719	\$478,969
Audit-Related Fees ⁽¹⁾	\$14,712	\$11,175
Tax Fees ⁽²⁾	\$29,031	\$8,325
All Other Fees ⁽³⁾	\$278,724	\$92,415
TOTAL	\$999,186	\$590,884

Notes:

- (1) Represent the aggregate fees billed by E&Y for assurance and related services that were reasonably related to the performance of the audit or review of the Trust's financial statements and were not reported under "Audit Fees". The nature of the services was for accounting advice.
- (2) Represent the aggregate fees billed by E&Y for professional services for tax compliance, tax advice and tax planning. The nature of the services was tax services and tax planning.
- (3) Represent the aggregate fees billed by E&Y for products and services, other than those reported with respect to the other categories of service fees. The nature of the services was for translation services and non-audit/tax related fees.

The foregoing information is also set forth in the Trust's Annual Information Form for the year ended December 31, 2007, under the heading "*General Partner – Directors and Officers - External Auditor Service Fees by Category*".

E&Y were the auditors of AltaGas Services Inc. (the predecessor to AltaGas) since April 30, 1997 and became the auditors of the Trust on May 1, 2004, the effective date of the plan of arrangement pursuant to which the Trust was created and acquired the business of AltaGas Services Inc. (the "Arrangement").

Representatives of E&Y will be present at the Meeting and will have the opportunity to make a statement and to respond to appropriate questions.

INTEREST OF CERTAIN PERSONS OR COMPANIES IN MATTERS TO BE ACTED UPON

Other than as set forth herein, the General Partner and AltaGas are not aware of any material interest, direct or indirect, by way of beneficial ownership of securities or otherwise, of any current or nominee member of the board of directors or executive officer of AltaGas, respectively, at any time since the beginning of the Trust's last financial year, or any associate or affiliate of any of the foregoing persons, in any matter to be acted upon other than the election of directors or the appointment of auditors.

INTEREST OF INFORMED PERSONS IN MATERIAL TRANSACTIONS

The General Partner and AltaGas are not aware of any material interest, direct or indirect, of any informed person of the Trust, any nominee director of the General Partner, or any associate or affiliate of any informed person or nominee director, in any transaction since the commencement of the Trust's most recently completed financial year, or in any proposed transaction, that has materially affected or would materially affect the Trust or any of its subsidiaries.

For the purposes of this Information Circular an "informed person" means, in the context of the Trust, a director or executive officer of any subsidiary of the Trust, including without limitation the General Partner, AltaGas Holding Trust ("**Holding Trust**"), AltaGas LP #1, AltaGas LP #2 and AltaGas.

INDEBTEDNESS OF DIRECTORS AND EXECUTIVE OFFICERS

The General Partner and AltaGas are not aware of any individuals who are, or who at any time during the most recently completed financial year were, a director of the General Partner or executive officer of AltaGas, a proposed nominee for election as a director of the General Partner, or an associate of any of those directors, executive officers or proposed nominees, who are, or have been at any time since the beginning of the most recently

completed financial year of the Trust, indebted to the Trust or any of its subsidiaries or whose indebtedness to another entity is, or at any time since the beginning of the most recently completed financial year of the Trust, has been, the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Trust or any of its subsidiaries.

TRUST GOVERNANCE

General

Pursuant to a delegation agreement dated May 1, 2004 among the Trust, the General Partner and the Trustee, the board of directors is responsible for managing the business and affairs of the Trust generally and believes that good governance improves performance and benefits all Unitholders. The board of directors is therefore committed to a high standard of governance. In addition, pursuant to a unanimous shareholder agreement dated May 1, 2004 among the General Partner, AltaGas LP #1, AltaGas LP #2 and AltaGas (the "**Unanimous Shareholder Agreement**"), AltaGas has granted to the General Partner the power, among other things, of the directors of AltaGas to appoint the executive officers of AltaGas and to manage, or to supervise the management of, the business and affairs of AltaGas. Finally, pursuant to an administration agreement dated May 1, 2004 among AltaGas, the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, AltaGas is responsible for providing administrative support services to, and for the management and general administration of the affairs of, the Trust.

The General Partner on behalf of the Trust has structured its governance to comply with applicable legislation and policies, including National Policy 41-201 – *Income Trusts and Other Indirect Offerings*, Multilateral Instrument 52-110 – *Audit Committees* ("**MI 52-110**"), National Policy 58-201 – *Corporate Governance Guidelines* ("**NP 58-201**") and National Instrument 58-101 – *Disclosure of Corporate Governance Practices* ("**NI 58-101**"). **Attached as Schedule A – Statement of General Partner's Governance Practices to this Information Circular is a description of the General Partner's corporate governance practices with specific reference to NI 58-101 and MI 52-110.** The board of directors believes that the General Partner's governance policies and practices are fully compliant with the requirements of MI 52-110 and NI 58-101 and with the guidelines of NP 58-201. In addition, the General Partner stays abreast of legislative and other policy initiatives pertaining to corporate governance matters and proactively seeks to adjust its corporate governance to address such potential requirements.

The board of directors discharges its responsibilities directly and through its committees. At regularly scheduled meetings, the board of directors and management of AltaGas discuss the issues relevant to the Trust's strategy and business. Currently, the board of directors meets a minimum of five times per year and in 2007 met twelve (12) times. The nature of the business discussed and conducted by the board of directors at any particular meeting is dependent on the then-current state of the Trust's business and the opportunities and risks that the Trust faces at that time. However, every regularly scheduled quarterly board of directors' meeting includes a review of the Trust's consolidated financial and operational status and performance and a report from any committees that have met since the last board meeting.

Management's responsibilities are clearly defined by the board of directors. This is accomplished by identifying the roles and responsibilities of the Chief Executive Officer and Chief Financial Officer of the General Partner and by defining the mandates of the board of directors and the committees thereof.

Board Committees

The board of directors has established four committees: the Audit Committee, the Governance Committee, the Environment, Occupational Health and Safety Committee and the Human Resources and Compensation Committee. All of the members of the Audit Committee, the Governance Committee and the Human Resources and Compensation Committee are "independent" directors, within the meaning of MI 52-110. In addition, a majority of members of the Environment, Occupational Health and Safety Committee are independent directors.

Pursuant to the Unanimous Shareholder Agreement, the committees of the board of directors have authority over both the General Partner and AltaGas on those matters covered by their respective mandates.

Audit Committee

The board of directors has developed written terms of reference outlining the Audit Committee's roles and responsibilities and provides appropriate guidance to Audit Committee members as to their duties. These terms of reference are reviewed annually by the board of directors. The Audit Committee reviews the annual and interim financial statements of the Trust and makes recommendations to the board of directors with respect to those statements. The Audit Committee also reviews the nature and scope of the annual audit as proposed by the auditors and management, and the adequacy of the internal accounting control procedures and systems within AltaGas. The Audit Committee is responsible for ensuring that management has implemented an effective system of internal control and has oversight responsibility for management reporting on internal control.

The Audit Committee meets with the Trust's auditors regularly, independent of management, and has direct communication channels with the Trust's external and internal auditors to discuss and review specific issues as appropriate.

Further information in respect of the Audit Committee and its members and mandate is contained under the heading "*General Partner – Directors and Officers*" in, and is attached as Schedule "A" to, the Trust's annual information form for the year ended December 31, 2007. The annual information form is available under the Trust's profile on SEDAR at www.sedar.com.

The Audit Committee currently consists of Allan L. Edgeworth, Daryl H. Gilbert and Robert B. Hodgins, all of whom are independent directors. Robert B. Hodgins is the chair of the Audit Committee.

Governance Committee

The Governance Committee is responsible for the development of the overall governance of the Trust and its affiliates; a continuing assessment of corporate governance matters; and making recommendations to the board of directors regarding the Trust's approach to corporate governance.

The Governance Committee currently consists of Robert B. Hodgins, Myron F. Kanik and David F. Mackie, all of whom are independent directors. Myron F. Kanik is the chair of the committee and the Lead Director.

Environment, Occupational Health and Safety Committee

The Environment, Occupational Health and Safety Committee monitors and makes recommendations to the board of directors with respect to the environment, health and safety policies, practices and procedures of the Trust's affiliates, including AltaGas and its subsidiaries. The committee has established an environmental risk management system and monitors its operation through regular reports.

The Environment, Occupational Health and Safety Committee currently consists of David W. Cornhill, Allan L. Edgeworth and Denis C. Fonteyne, of whom Messrs. Edgeworth and Fonteyne are independent directors. Denis C. Fonteyne is the chair of the committee.

Human Resources and Compensation Committee

The mandate of the Human Resources and Compensation Committee includes developing appropriate compensation policies for the senior management of AltaGas and evaluating senior management performance. These responsibilities include reporting and making recommendations to the board of directors for their consideration and approval.

The Human Resources and Compensation Committee currently consists of Denis C. Fonteyne, Daryl H. Gilbert, Myron F. Kanik and David F. Mackie, all of whom are independent directors. Myron F. Kanik is the chair of the committee.

REPORT ON EMPLOYEE AND EXECUTIVE COMPENSATION

The Human Resources and Compensation Committee

The mandate of the Human Resources and Compensation Committee (the "**HR Committee**") includes developing appropriate compensation policies for the senior management of AltaGas, including AltaGas' Mid Term Incentive Plan and Trust Unit Option Plan, and evaluating senior management performance. Following review of data and discussion by members of the HR Committee, recommendations are made by the HR Committee to the board of directors for their consideration and approval. In all cases, the board of directors has acted upon HR Committee recommendations without modification in any material way. The HR Committee meets at least quarterly to fulfill its mandate.

The HR Committee currently consists of Denis C. Fonteyne, Daryl H. Gilbert, Myron F. Kanik and David F. Mackie, all of whom are independent directors. Myron F. Kanik is chair of the committee. None of the members of the committee was an officer or employee of AltaGas or any of its subsidiaries in the most recently completed financial year; was formerly an officer of AltaGas or any of its subsidiaries; or had or has any relationship that requires disclosure under the headings "*Indebtedness of Directors and Executive Officers*" or "*Interest of Informed Persons in Material Transactions*" in this Information Circular; was an executive officer of AltaGas and also served as a member of the compensation committee (or equivalent) of another issuer, one of whose executive officers served on the HR Committee; was an executive officer of AltaGas and also served as a director of another issuer, one of whose executive officers served on the HR Committee; or was an executive officer of AltaGas and also served as a member of the compensation committee (or equivalent) of another issuer, one of whose executive officers served as a director of the General Partner.

Compensation Policy

The philosophy of the board of directors is that if the Trust does well, the employees of AltaGas will be rewarded through cash bonuses, increases in long-term variable compensation, such as Trust Unit Options and MTIP incentive awards, additional long-term variable compensation awards or combinations of any or all of the foregoing. The goal of the HR Committee in making compensation recommendations is to recognize and reward individual performance as well as to provide a competitive industry level of compensation, taking into consideration the individual's experience and performance and the financial performance of the Trust.

AltaGas' human resources department reviews industry compensation information provided by consultants and compares its level of overall compensation with those of comparably-sized trusts and companies. A summary of this information is provided to the HR Committee to assist in approving AltaGas' overall compensation policy and the compensation to be paid, especially to the senior officers. The HR Committee also periodically independently retains external consultants to review compensation matters. Comparable trusts and corporations are chosen based on their being in the oil and gas industry. Comparable positions are identified based on publicly available information on such organizations.

The HR Committee views total compensation as a linked strategy towards achieving overall performance targets and has designed a total compensation package of short-term and long-term compensation with fixed and variable compensation components. Currently the compensation program for employees of AltaGas consists of salary, benefits and the Short Term Incentive Plan by way of short-term compensation; and the Trust Unit Option Plan, the Mid Term Incentive Plan, the Employee Unit Purchase Savings Plan, the Group RRSP, the Defined Contribution Pension Plan and the Supplementary Executive Pension Plan by way of long-term compensation.

AltaGas emphasizes fair annual fixed and variable compensation to provide an immediate incentive for short-term performance. Some emphasis is also placed on longer-term compensation, the focus of which is longer-term commitment by AltaGas' officers and employees.

Annual Salary

Annual salary is intended to provide a competitive rate of compensation and recognize the skills, competencies and level of responsibility of employees. Generally, the HR Committee targets base salaries at levels approximating those holding similar positions in comparably-sized organizations in the industry (as outlined above) and hopes to achieve targeted total compensation levels through other fixed and variable compensation components.

Short Term Incentive Plan

AltaGas implemented a Short Term Incentive Plan for permanently employed executive officers and employees of AltaGas to provide annual cash bonuses following the fiscal year end.

In order to reward individual performance, eligibility for compensation under the Short Term Incentive Plan is linked to individual, team and Trust performance. The more senior the position in the organization, the greater the weighting towards Trust measures. Team and individual performance for each employee are assessed annually against objectives set at the beginning of each year. Team performance objectives include, for example, business segment results such as return on investment or operating income. Individual performance objectives include pre-determined individual targets.

Trust performance is measured based on consolidated financial results weighted 50 percent on return on equity ("ROE") and 50 percent on net income per Trust Unit ("NIPU") against a pre-determined target for each set at the beginning of each year. The Trust performance indicators under the Short Term Incentive Plan in respect of the 2007 year were ROE of 18.30 percent and NIPU of \$1.70 per Trust Unit, compared with, respectively, 2006 ROE of 19.09 percent and NIPU of \$1.66 per Trust Unit. See also "*Report on Employee and Executive Compensation - Performance Graph*" for changes in the cumulative Unitholder return of AltaGas over time and as compared with key industry indicators.

No awards are made to any executive officers or employees under the Short Term Incentive Plan in cases where those executive officers or employees did not meet the objectives applicable to them.

Mid Term Incentive Plan

AltaGas has adopted a Mid Term Incentive Plan ("MTIP") for directors, officers and employees as an additional form of long-term variable compensation incentive. The purpose of the MTIP is to link a portion of the at-risk compensation to the achievement of both the Trust's performance targets and individual performance targets, and to thereby promote the attraction, motivation and retention of highly qualified individuals.

The incentive bonus compensation contemplated under the MTIP will be granted in the form of both time-vested restricted units ("RUs") and performance-vested units ("PUs"). Unless otherwise determined by the HR Committee, the RUs will vest as to one-third per year over a three-year period commencing with the year of grant, contingent upon the Trust achieving a threshold level of performance during each year of the vesting period. The PUs will vest at the end of a three-year period commencing with the year of grant, contingent upon the Trust achieving a threshold level of performance during the three-year vesting period.

The HR Committee will determine in its sole discretion the appropriate performance vesting criteria for the purpose of the RU and PU aspects of the MTIP. That authority has been delegated to the General Partner pursuant to the Unanimous Shareholder Agreement. Factors considered in granting RUs and PUs include the extent to which individual performance targets are achieved and the level of RUs and PUs granted to similarly placed and qualified individuals in AltaGas.

The MTIP functions as follows:

- (a) the board of directors approves individual grants under the MTIP that are a function of the extent to which individual performance targets were achieved and the level of total compensation provided to similarly placed and qualified individuals in AltaGas and comparable-sized entities;
- (b) following the determination of an individual's grant, the cash value of the grant is converted to phantom whole units (either RUs or PUs at the discretion of the board of directors) equal to the number of whole Trust Units that such individual's grant would have been able to acquire at the date of grant, based on the fair market value ("FMV") of the Trust Units. For that purpose, the FMV of the Trust Units is equal to the average of the closing prices of the Trust Units on the Toronto Stock Exchange (the "TSX") (or if the Trust Units are not then listed on the TSX then such other exchange upon which the Trust Units are listed) for the immediately preceding 80 trading days prior to the date of grant;

- (c) the RUs and PUs are tracked during the applicable vesting period and distributions on a Trust Unit during that period are deemed to be paid on the dates of distribution on each PU and RU and reinvested to acquire more phantom whole units and accrue to the benefit of that individual in the accounts maintained for that individual, to be paid to the individual if and to the extent vesting occurs; and
- (d) upon the vesting of RUs or PUs, and contingent upon the applicable performance criteria being achieved, AltaGas has the option to pay out the FMV of the RUs or PUs (including the additional units acquired on reinvestment of the accrued distributions in respect thereof), as the case may be, in cash or in Trust Units equivalent in value acquired by the plan administrator in the open market.

Trust Unit Option Plan

AltaGas adopted a Trust Unit Option Plan as a continuing form of long-term variable compensation incentive for directors, officers, employees, consultants and other personnel of the Trust and any of its subsidiaries, including AltaGas. The quantum and granting of options ("**Trust Unit Options**") is related to individual performance and is used as an incentive to attract, retain and motivate a highly qualified staff. Factors considered in granting new Trust Unit Options and the terms of those Trust Unit Options include the extent to which individual performance targets were achieved and the level of Trust Unit Options granted to similarly placed and qualified individuals in AltaGas and comparable organizations.

The Trust Unit Option Plan provides that the maximum number of Trust Units issuable upon the exercise of all Trust Unit Options granted under the Trust Unit Option Plan, together with Trust Units as may be subject to options pursuant to other security-based compensation arrangements, shall not exceed 10 percent of the aggregate of the outstanding Trust Units and any other securities exchangeable into Trust Units, including the Exchangeable Units, or such greater number of Trust Units as may be determined by the board of directors and approved, if required, by the Unitholders and by the TSX, not exceeding the maximum number of Trust Units permitted under the rules of the TSX.

Employee Unit Purchase Savings Plan

The Employee Share Purchase Savings Plan was implemented by AltaGas in 2000 to encourage equity ownership by employees, as a long-term incentive and to ensure AltaGas' compensation was competitive in the oil and gas industry. The Employee Share Purchase Savings Plan was changed to an Employee Unit Purchase Savings Plan on conversion to the Trust in May 2004. All employees of AltaGas are eligible to participate.

Employees can contribute up to 10 percent of their base pay into the savings plan. AltaGas will match employee contributions up to a maximum of 2.5 percent of base pay for those employees with up to three years of service; 3.75 percent of base pay for those employees with three to six years of service; and 5 percent of base pay for those employees with more than six years of service. Employee contributions can be invested in Trust Units, a short-term investment fund or a combination of such investments. AltaGas' contributions are invested in Trust Units.

Group RRSP

Until July 1, 2005, AltaGas coordinated a group (the "**Group RRSP**") registered retirement savings plan ("**RRSP**") whereby employee contributions into their self-directed RRSPs were matched by AltaGas at a rate of 80 percent of the employee's contribution, to a maximum of 4.8 percent of base pay. AltaGas will continue to enable individuals to make RRSP contributions to the Plan through payroll deduction, but with the commencement of the DC Plan (as defined below) will not match such contributions, except in the case of David W. Cornhill, Chief Executive Officer, who continues to receive matching in lieu of participation in the DC Plan.

Pension Plan and Supplemental Executive Retirement Plan

(a) AltaGas Defined Contribution Pension Plan

On July 1, 2005, AltaGas instituted a registered defined contribution pension plan (the "**DC Plan**") for employees, including executive officers. The DC Plan provides for AltaGas contributions of 4 percent of employee base salary plus a service-related match of employee optional contributions of up to 2 percent of the employee's

base salary. All regular employees, excluding the Chief Executive Officer, participate in the DC Plan. AltaGas contributions on behalf of employees vest after two years of employment with AltaGas or a related company. Employees direct the investment of their own and AltaGas' contributions in one or a combination of 18 different investment options.

(b) AltaGas Supplemental Executive Retirement Plan

On July 1, 2005, AltaGas instituted a non-registered defined benefit retirement plan for executive officers to supplement their AltaGas-sponsored registered retirement savings (being the Group RRSP and DC Plan). The SERP benefit is determined such that the value of each member's total retirement benefit is equal to the value of an annual defined benefit pension of 2 percent of the member's highest three-year average earnings multiplied by the member's years of pensionable service.

For purposes of determining the value:

- (i) earnings are defined as the member's base salary plus 50 percent of his or her target bonus;
- (ii) upon enrolling in the SERP, a member will have the portion of his or her AltaGas employment service that exceeds five years immediately recognized as pensionable service;
- (iii) each year going forward the member will receive credit for two years of pensionable service until his or her pensionable service is equal to his or her AltaGas employment service. Thereafter, one year of pensionable service will be credited for each year of continuing employment service;
- (iv) the retirement benefit is a joint life pension with a guarantee that at least five years of payments will be made. If the member was married at retirement, after the death of the member, and the expiration of the five-year guarantee, the pension will be reduced to 60 percent for the remainder of the spouse's lifetime; and
- (v) the member with at least five years of pensionable service may retire as early as age 55. The accrued retirement benefit will be reduced by 3 percent per year that retirement precedes the member's attainment of age 60.

The SERP will provide the difference between the value of the total retirement benefit determined above, and the value of the Member's DC Plan and Group RRSP entitlement. The SERP will pay this value to the member in equal payments from the date of the member's retirement to the date the member attains age 70.

The SERP benefits will be paid from the general revenue of AltaGas as payments become due. Security for the accruing liability will be provided through a letter-of-credit arrangement.

Chief Executive Officer Compensation

The HR Committee has the responsibility for reviewing AltaGas' compensation policies. The HR Committee makes recommendations to the board of directors as to remuneration for the Chief Executive Officer.

The policy of the HR Committee with respect to compensation for the Chief Executive Officer is to set his base salary, total cash compensation (which includes short term-incentives) and total direct compensation (which includes long-term incentives) at approximately the median among public trusts and companies in the Canadian oil and gas industry of comparable size and complexity. A comparator group of peer companies was initially developed in 2001 based on those industry compensation survey participants whose revenues or assets were within 50 percent and 200 percent of those of the Trust. The peer group composition is reviewed annually to ensure that it continues to provide a reasonable basis for comparison.

The HR Committee considers among other things, data from industry compensation surveys and the overall performance of the Trust, including ROE, NIPU, successful acquisitions and the successful implementation of the Trust's strategy.

The Chief Executive Officer's salary, short-term incentives, MTIP grants and Trust Unit Option awards are determined based on the overall success of the Trust. The Chief Executive Officer's entitlement under AltaGas'

Short Term Incentive Plan is based on a combination of corporate performance (70 percent) and team-individual performance (30 percent). Corporate performance is measured relative to preset targets for ROE and NIPU.

Grants under the MTIP are an additional form of long-term variable compensation incentive. The quantum and granting of RUs and PUs under the MTIP is related to competitive conditions determined as outlined above and individual performance.

Trust Unit Options are granted dependent on the number of Trust Unit Options available for grant, competitive conditions determined as outlined above and individual performance.

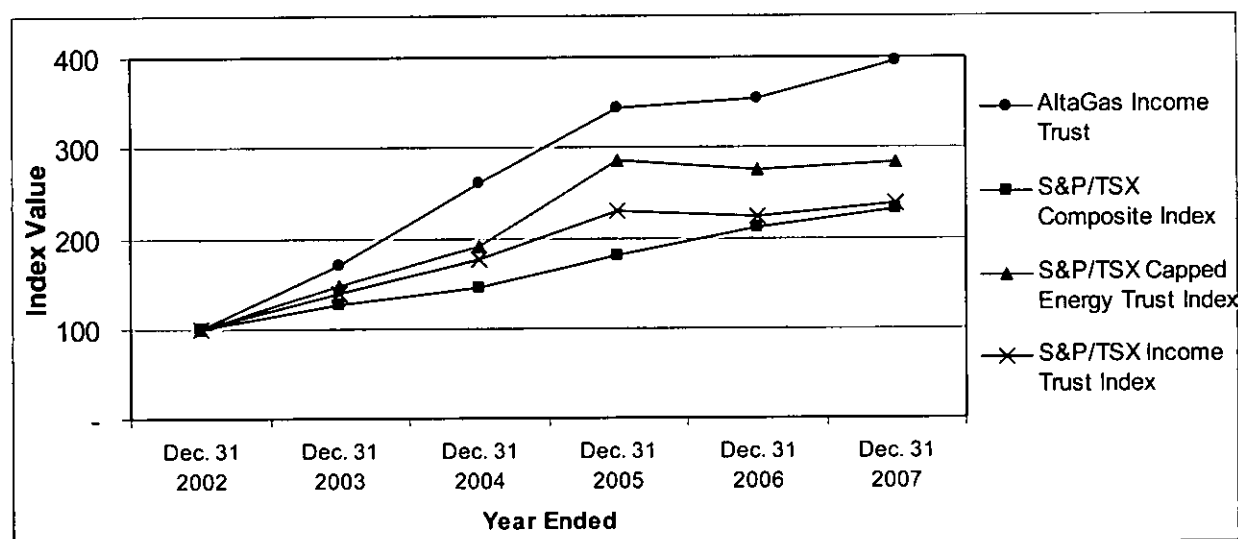
Mr. Cornhill, the Chief Executive Officer and a director of the General Partner, does not vote and is excused from Board and Committee meetings with respect to compensation matters affecting him.

PERFORMANCE GRAPH

The Common Shares of AltaGas Services Inc. were listed on the TSX on January 17, 2000. Following the Effective Date of the Arrangement, the Trust Units were listed on the TSX in substitution for the Common Shares of AltaGas Services Inc. and are included in the S&P/TSX Capped Energy Trust, S&P/TSX Income Trust and S&P/TSX Composite indices.

The following table and graph compare the yearly percentage change in the cumulative Unitholder return over the last five years on the Common Shares and Trust Units, respectively (assuming a \$100 investment was made on December 31, 2002) with the cumulative total return of the S&P/TSX Composite Index, the S&P/TSX Capped Energy Trust Index and the S&P/TSX Income Trust Index. The values assume the reinvestment of any declared dividends or distributions.

	Dec. 31 2002	Dec. 31 2003	Dec. 31 2004	Dec. 31 2005	Dec. 31 2006	Dec. 31 2007
AltaGas	100	169	260	345	354	396
S&P/TSX Composite Index	100	127	145	180	211	232
S&P/TSX Capped Energy Trust Index	100	146	191	285	275	284
S&P/TSX Income Trust Index	100	138	175	230	223	238



EXECUTIVE COMPENSATION

As indicated above under “*Trust Governance*”, the Trust has no management personnel, as the management and administration of the Trust has been delegated to the General Partner and AltaGas, respectively. Accordingly, the following provides information on compensation paid to AltaGas’ executive officers. As described above under “*Report on Employee and Executive Compensation*”, compensation of AltaGas’ executive officers, as with all of AltaGas’ employees, includes short-term and long-term compensation with fixed and variable components designed to recognize and reward individual performance and provide an industry-competitive level of compensation.

For the purposes of this section, “executive officer” means the chair and any vice-chair of the board of directors; the president; any vice president in charge of a principal business unit, division or function such as sales, finance or production; any officer of any subsidiary of the Trust, including AltaGas or of a subsidiary of AltaGas who performed a policy-making function in respect of the Trust, and any other person who performed a policy-making function in respect of the Trust. A “Named Executive Officer” means, collectively:

- (a) the President and Chief Executive Officer (“CEO”) of the General Partner and of AltaGas;
- (b) the Chief Financial Officer (“CFO”) of the General Partner and of AltaGas;
- (c) AltaGas’ three most highly compensated executive officers other than the CEO and CFO who were serving as executive officers at the end of the most recently completed financial year and whose respective total salary and bonus exceeded \$150,000; and
- (d) any other individuals for whom disclosure would have been provided under (c) but for the fact that they were not serving as an officer of AltaGas at the end of the most recently completed financial year.

The following table sets forth information concerning the compensation paid by AltaGas to its Named Executive Officers for the three most recently completed financial years.

Name and Principal Position	Year Ended Dec. 31	Annual Compensation			Long-Term Compensation				All Other Compensation ^{(4) (5)} (\$)	Total Compensation (\$)
		Salary (\$)	Bonus (\$) ⁽¹⁾	Other Annual Compensation ⁽²⁾ (\$)	Awards		Payouts			
					Securities Under Options/SARs Granted ⁽³⁾ (#)	Units Subject to Resale Restrictions (\$)	Long-Term Incentive Plan Payouts (\$)			
David W. Cornhill ⁽⁶⁾ Chairman of the Board, President and Chief Executive Officer	2007	535,000	580,000	-	69,860 PUs	-	-	2,531,203	3,646,203	
	2006	500,000	462,345	-	48,225 PUs	-	-	739,304	1,725,650	
	2005	435,000	424,720	-	4,500 RUs	-	-	2,715,947	3,575,667	
Richard M. Alexander ⁽⁷⁾ Executive Vice President, Chief Operating Officer and Chief Financial Officer	2007	320,000	237,386	-	16,000 PUs	-	-	302,058	859,444	
	2006	186,667	-	-	30,000 RUs	-	-	514,000	700,667	
	2005	-	-	-	50,000 PUs	-	-	-	-	
Kent E. Stout Vice President Corporate Resources	2007	203,000	103,478	-	8,000 PUs	-	-	684,935	991,413	
	2006	189,000	94,500	-	8,050 PUs	-	-	86,215	369,716	
	2005	180,000	88,128	-	1,800 RUs	-	-	54,415	322,543	

Name and Principal Position	Year Ended Dec. 31	Annual Compensation			Long-Term Compensation				Total Compensation (\$)
		Salary (\$)	Bonus (\$) ⁽¹⁾	Other Annual Compensation ⁽²⁾ (\$)	Awards		Payouts	All Other Compensation ^{(4) (5)} (\$)	
					Securities Under Options/SARs Granted ⁽³⁾ (#)	Units Subject to Resale Restrictions (\$)	Long-Term Incentive Plan Payouts (\$)		
Jeffrey F. Perry	2007	198,425	85,466	-	8,000 PUs	-	-	751,796	1,035,688
Divisional Vice President	2006	189,925	78,281	-	7,500 PUs	-	-	14,838	283,044
Field Gathering and Processing	2005	173,958	58,968	-	1,000 PUs	-	-	11,325	244,251
Dennis A. Dawson	2007	220,000	133,120	-	9,000 PUs	-	-	943,282	1,296,402
Vice President, General Counsel and Corporate Secretary	2006	208,000	118,800	-	6,750 PUs	-	-	236,812	563,612
	2005	198,000	122,208	-	2,100 RUs	-	-	1,225,673	1,345,881
Marshal L. Thompson ⁽⁸⁾	2007	111,471	143,808	-	1,000 PUs	-	-	752,598	1,007,877
Senior Vice President External Relations and Corporate Risk	2006	214,000	123,814	-	10,000 PUs	-	-	36,717	374,531
	2005	201,250	97,611	-	1,350 RUs	-	-	17,924	316,785
Patricia M. Newson	2007	-	-	-	-	-	-	2,794,314	2,794,314
Senior Vice President	2006	-	324,479	-	-	-	-	445,908	770,387
	2005	263,542	163,800	-	3,000 RUs	-	-	486,383	913,724

Notes:

- (1) Bonus amounts tabled reflect the bonus paid in the respective years. See discussion in more detail above under "Report on Executive and Employee Compensation – Compensation Policy – Short Term Incentive Plan".
- (2) Other than as indicated above, the value of other annual compensation was no greater than the lesser of \$50,000 and 10 percent of the total annual salary and bonus of each Named Executive Officer in each financial year.
- (3) See discussion of the MTIP in more detail above under "Report on Executive and Employee Compensation – Compensation Policy – Mid Term Incentive Plan".
- (4) AltaGas makes contributions under the Employee Unit Purchase Savings Plan, the Group RRSP (for David W. Cornhill) and the Pension Plan. Also includes amounts paid pursuant to the MTIP, and amounts earned pursuant to the exercise of Trust Unit Options. Includes amount paid to Ms. Newson in 2006 in lieu of vacation. These plans are described in more detail above under "Report on Executive and Employee Compensation – Compensation Policy – Employee Unit Purchase Savings Plan", "– Group RRSP", "– Pension Plan and Supplemental Executive Retirement Plan" and "– Mid Term Incentive Plan", respectively.
- (5) Includes amounts paid in 2005, 2006 and 2007, respectively, regarding a change of control under Employment Agreements with David W. Cornhill, Patricia M. Newson and Dennis A. Dawson. The Employment Agreements and the retention arrangements required as a result of the change of control are described in more detail below under "Executive Compensation – Employment Agreements" and "Executive Compensation – Retention of Employees on Change of Control".
- (6) Upon Richard M. Alexander's appointment as President and Chief Operating Officer on January 21, 2008, David W. Cornhill resigned as President and continued in his position of Chief Executive Officer.
- (7) Richard M. Alexander was appointed President and Chief Operating Officer on January 21, 2008.
- (8) Marshal L. Thompson resigned effective June 6, 2007.

The total cash compensation for the CEO and the aggregate total cash compensation for the CEO, CFO and the other Named Executive Officers are shown below:

	2005	2006	2007
CEO ⁽¹⁾	\$3,575,667	\$1,725,650	\$3,646,203
Total Aggregate of CEO, CFO and other Named Executive Officers	\$6,718,851	\$4,792,607	\$11,631,341
Total Aggregate of CEO, CFO and Named Executive Officers as percentage of total market capitalization ⁽¹⁾⁽²⁾	0.44%	0.32%	0.76%
Unitholder Total Return	31.5%	1.1%	9.4%

Notes:

- (1) The total cash compensation and aggregate cash compensation includes salary, bonus and other compensation, including MTIP proceeds calculated in the same manner as in the Executive Compensation table above.
- (2) Assuming market capitalization of \$1,527,400,029, \$1,477,741,989 and \$1,536,108,317 as at December 31, 2005, December 31, 2006 and December 31, 2007, respectively.

Employment Agreements

AltaGas is party to employment agreements with David W. Cornhill, Richard M. Alexander and Dennis A. Dawson. AltaGas was party to an employment agreement with Patricia M. Newson. The agreements are discussed below.

AltaGas Services Inc. was a party to an employment agreement with each of David W. Cornhill, AltaGas' Chairman, President and Chief Executive Officer; Patricia M. Newson, AltaGas' Senior Vice President; and Dennis A. Dawson, AltaGas' Vice President, General Counsel and Corporate Secretary (collectively, the "**Services Employment Agreements**"). Those Services Employment Agreements were amended and restated effective May 1, 2004 in connection with the Arrangement so that those agreements for the most part have similar terms and conditions. Each of the amended and restated Services Employment Agreements was effective May 1, 2004. The amended and restated Services Employment Agreement with Ms. Newson terminated effective January 1, 2006, other than the obligation to make all payments owing in connection with her employment with AltaGas, including those set forth in the Executive Compensation table above. The Services Employment Agreement with Mr. Cornhill was further amended and restated effective January 1, 2007 in order to, among other things, increase base salary, provide for allocations of PUs under the MTIP, amend entitlements under the SERP and otherwise adjust the compensation payable to Mr. Cornhill on the occurrence of certain events.

Effective January 1, 2007, AltaGas entered into an employment agreement with Richard M. Alexander (together with the Services Employment Agreements, the "**Employment Agreements**") on substantially similar terms and conditions as the Services Employment Agreements.

The terms of the Employment Agreements with Mr. Cornhill, Mr. Dawson and Mr. Alexander continue indefinitely. The base salaries provided in those agreements for each of those Named Executive Officers are indicated in the Annual Compensation table provided above.

The amended and restated Services Employment Agreement with Mr. Cornhill provides for termination by AltaGas for just cause or in the event of the permanent disability of Mr. Cornhill, and was to terminate automatically in the event of the death of Mr. Cornhill. The amended and restated Services Employment Agreement also provides for termination by AltaGas upon the giving of notice and the payment by AltaGas of an amount (the "**Retirement Allowance**") equal to the sum of (a) two times the product of the annual base salary paid to Mr. Cornhill in the last full month of employment multiplied by the annual target bonus percentage then applicable; (c) a cash amount equal to the value of certain benefit entitlements for a two-year period; and (d) a cash amount equal to the product of 24 times the value on a monthly basis of the car provided to him.

If at any time during the term of the amended and restated Services Employment Agreement with Mr. Cornhill there is a "change of control" (as defined below), Mr. Cornhill is entitled, at any time after six months but before one year, after the effective date of such change of control, to terminate his employment with AltaGas by the giving of 60 days' notice to that effect. In that event, or if AltaGas terminates his amended and restated

Employment Agreement within a period of one (1) year after such change of control, Mr. Cornhill is entitled to a Retirement Allowance equal to the sum of 30 times: (a) the gross monthly base salary paid to Mr. Cornhill in the last full month of employment; (b) the product of the gross monthly base salary paid to Mr. Cornhill in the last full month of employment multiplied by the annual target bonus percentage then applicable; (c) a cash amount equal to the value of certain benefit entitlements expressed as a monthly amount; and (d) a cash amount equal to the value on a monthly basis of the car provided to him. "Change of control" for the purposes of Mr. Cornhill's and Mr. Dawson's Employment Agreements includes the acquisition of control by any means and "control" includes the power to direct or cause the direction of the management and policies of AltaGas or any applicable affiliate. The definition of change of control in each of the amended and restated Services Employment Agreements was modified to reflect that given the organization structure of the Trust, a change of control could occur by acquiring control of the Trust Units of AltaGas or any of the entities above AltaGas in the structure. The definition of change of control in Mr. Alexander's Employment Agreement reflects the same modification.

The definition of change of control in the Services Employment Agreement of Mr. Cornhill includes the restructuring of the business of AltaGas or the Trust to eliminate the trust structure so that the business is conducted by a corporate entity. In contrast, the definition of change of control in Mr. Alexander's and Mr. Dawson's Employment Agreements does not contemplate such a restructuring constituting a change of control.

Mr. Cornhill is entitled to terminate his employment with AltaGas by giving six months notice to that effect. In this event, Mr. Cornhill is to be entitled to receive the Retirement Allowance.

The amended and restated Services Employment Agreement for Mr. Dawson is substantially the same as for Mr. Cornhill, except that the Retirement Allowance payable under Mr. Dawson's amended and restated Services Employment Agreement is equal to two times (a) the annual base salary paid to Mr. Dawson in the last full month of employment; (b) the product of the annual base salary in effect during the last month of employment multiplied by the annual target bonus percentage; (c) the value of the benefit entitlements for a one-year period; and (d) the value of the annual car allowance; and that if Mr. Dawson terminates his employment with AltaGas other than following a change of control (as defined) he is not entitled to receive the Retirement Allowance. Mr. Dawson is entitled, at any time after six months but before nine months after the effective date of a change of control, to terminate his employment with AltaGas and receive the Retirement Allowance by the giving of 60 days' notice to that effect.

The Employment Agreement for Mr. Alexander is substantially the same as for Mr. Cornhill and Mr. Dawson, except that the Retirement Allowance payable under Mr. Alexander's Employment Agreement is equal to two times (a) the annual base salary paid to Mr. Alexander in the last full month of employment; (b) the product of the annual base salary in effect during the last month of employment multiplied by the annual target bonus percentage; (c) the value of the benefit entitlements for a one-year period; and (d) the value of the annual car allowance; and that if Mr. Alexander terminates his employment with AltaGas other than following a change of control (as defined) he is not entitled to receive the Retirement Allowance. Mr. Alexander is entitled, at any time after six months but before nine months after the effective date of a change of control, to terminate his employment with AltaGas and receive the Retirement Allowance by the giving of 60 days' notice to that effect.

The amended and restated Services Employment Agreement with Ms. Newson terminated effective January 1, 2006, other than the obligation to make all payments owing in connection with her employment with AltaGas, including those set forth in the Executive Compensation table above. It was agreed that following the transfer by AltaGas of its utility assets to AltaGas Utility Group Inc. in November 2005 that Ms. Newson would become the President and Chief Executive Officer of AltaGas Utility Group Inc. and would devote approximately 60 percent of her business time and effort in 2006 and 80 percent of her business time and effort in 2007 to that corporation while retaining her positions as Chief Financial Officer of the General Partner and Senior Vice President Finance and Chief Financial Officer of AltaGas. On May 1, 2006, Richard M. Alexander joined AltaGas as Senior Vice President and Chief Financial Officer and Ms. Newson became Senior Vice President.

Other than pursuant to the Employment Agreements described above, there is no plan or arrangement in respect of compensation received or that may be received by Named Executive Officers in the most recently completed financial year with a view to compensating those officers in the event of termination of their employment or a change of responsibilities following a change in control.

Retention of Employees on Change of Control

The reorganization of the business of AltaGas Services Inc. into the Trust pursuant to the Arrangement constituted a change of control under the Services Employment Agreements with Mr. Cornhill, Ms. Newson and Mr. Dawson.

As a result of that change of control, each of Mr. Cornhill, Ms. Newson and Mr. Dawson were entitled to terminate their employment with AltaGas Services Inc. and receive the Retirement Allowance respectively payable to them in that event. In order to avoid the loss of these valued employees and their extensive knowledge of AltaGas Services Inc., AltaGas entered into agreements with each of these Named Executive Officers pursuant to which they waived their rights to terminate their employment with AltaGas Services Inc. on the basis of that change of control. In addition, each of those Named Executive Officers agreed on May 1, 2004 to continue their employment with AltaGas under the amended and restated Employment Agreements after the completion of the Arrangement in exchange for retention payments equal to their entitlements under their respective Services Employment Agreements. The payments were structured in the form of PUs and four equal cash instalments over a 21-month period on each of July 31, 2004, January 31, 2005, July 31, 2005 and January 31, 2006.

The total amount of the retention payments payable to each of these Named Executive Officers is equal to the Retirement Allowances that would have been payable to the applicable Named Executive Officer under the Named Executive Officer's Services Employment Agreement as a result of the change of control. The total amount of the retention payments paid, including the value of the PUs at the date of grant, to each of the Named Executive Officers was, respectively: David W. Cornhill, \$1,837,101; Patricia M. Newson, \$950,490; and Dennis A. Dawson, \$699,375. The Named Executive Officers had to be employed by AltaGas on the instalment payment date to receive the instalment payment and must have been employed by AltaGas on March 2, 2007 to have received the full amounts of the payments and the PUs. The PUs are subject to performance vesting criteria as discussed in "Executive Compensation – Mid Term Incentive Plan".

Trust Unit Option Grants and MTIP Grants

Except as set out below, no Trust Unit Options, RUs, PUs or other rights have been granted to any Named Executive Officer. The following table sets forth certain information relating to the RUs and PUs issued to the Named Executive Officers under the MTIP during the year ended December 31, 2007. There were no Trust Unit Options granted to Named Executive Officers in the financial year ended December 31, 2007.

Name	Grant Date	Securities Under Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Financial Year (%)	Exercise Price or Base Price (\$/Security) ⁽¹⁾	Market Value of Securities Underlying Options/SARS on the Date of Grant (\$/Security)	Expiration Date ⁽²⁾
David W. Cornhill	April 16, 2007	49,860 PUs	60.17	-	25.07	-
	December 10, 2007	20,000 PUs	23.46	-	25.02	-
Richard M. Alexander	April 16, 2007	4,000 PUs	4.83	-	25.07	-
	December 10, 2007	12,000 PUs	14.08	-	25.02	-
Kent E. Stout	April 16, 2007	1,500 PUs	1.81	-	25.07	-
	September 18, 2007	1,500 PUs	7.69	-	27.27	-
	December 10, 2007	5,000 PUs	5.87	-	25.02	-
Jeffrey F. Perry	April 16, 2007	2,000 PUs	2.41	-	25.07	-
	September 18, 2007	2,000 PUs	10.26	-	27.27	-
	December 10, 2007	4,000 PUs	4.69	-	25.02	-

Name	Grant Date	Securities Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Financial Year (%)	Exercise Price or Base Price (\$/Security) ⁽¹⁾	Market Value of Securities Underlying Options/SARS on the Date of Grant (\$/Security)	Expiration Date ⁽²⁾
Dennis A. Dawson	April 16, 2007	2,000 PUs	2.41	-	25.07	-
	September 18, 2007	2,000 PUs	10.26	-	27.27	-
	December 10, 2007	5,000 PUs	5.87	-	25.02	-
Marshal L. Thompson	April 16, 2007	1,000 PUs	1.21	-	25.07	-
Patricia M. Newson	-	-	-	-	-	-

Notes:

- (1) The base price varies with the market value of the Trust Units in the open market.
- (2) No Trust Unit Options were granted to Named Executive Officers in the financial year ended December 31, 2007. RUs and PUs do not have an expiration date. RUs vest as to one-third per year over a three-year period commencing with the year of grant, contingent upon AltaGas and the Trust achieving a threshold level of performance during each year of the vesting period while PUs will vest at the end of a three-year period commencing with the year of grant, contingent upon AltaGas and the Trust achieving a threshold level of performance during the three-year vesting period. See above under "Report on Executive and Employee Compensation – Compensation Policy – Mid Term Incentive Plan".
- (3) No Trust Unit Options, RUs or PUs were granted to Ms. Newson in the financial year ended December 31, 2007.

Trust Unit Option Exercises and Financial Year End Values

The following table sets forth information relating to aggregated exercises of Trust Unit Options by the Named Executive Officers during the year ended December 31, 2007 together with the number and value of unexercised Trust Unit Options held by each of the Named Executive Officers as at December 31, 2007.

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ⁽¹⁾ (\$)	Unexercised Options at Fiscal Year-End Exercisable / Unexercisable (#/#)	Value of Unexercised in- the-Money Options at Fiscal Year-End ⁽²⁾ Exercisable / Unexercisable (\$/\$)
David W. Cornhill	Nil	Nil	Nil / Nil	Nil / Nil
Richard M. Alexander	Nil	Nil	Nil / Nil	Nil / Nil
Kent E. Stout	Nil	Nil	Nil / Nil	Nil / Nil
Jeffrey F. Perry	Nil	Nil	15,000 / Nil	236,850 / Nil
Dennis A. Dawson	Nil	Nil	Nil / Nil	Nil / Nil
Marshal L. Thompson	Nil	Nil	Nil / Nil	Nil / Nil
Patricia M. Newson	Nil	Nil	Nil / Nil	Nil / Nil

Notes:

- (1) For the purpose of calculating the aggregate value realized, the exercise price of each Trust Unit Option exercised was subtracted from the closing trading price for the Trust Units on the TSX on the day on which the Trust Unit Options were exercised, and the resulting value was multiplied by the number of Trust Units obtained on exercise of Trust Unit Options. Note that all Trust Units obtained on exercise of Trust Unit Options may not have been sold, so that these values may not have been actually realized by the optionees.

- (2) For the purpose of calculating the in-the-money values of the Trust Unit Options, the exercise price of each Trust Unit Option would be subtracted from the closing price of the Trust Units on the TSX on December 31, 2007, the last trading day in the Trust's financial year ended December 31, 2007, which was \$26.44.

Pension Plans

The following table represents an estimate of the combined retirement benefit entitlement of an executive officer from the SERP, the DC Plan and the Group RRSP at the levels of remuneration and the years of service shown.

Remuneration ⁽¹⁾	Years of Pensionable Service		
	5	10	15
200,000	\$20,000	\$40,000	\$60,000
250,000	\$25,000	\$50,000	\$75,000
300,000	\$30,000	\$60,000	\$90,000
350,000	\$35,000	\$70,000	\$105,000
400,000	\$40,000	\$80,000	\$120,000
500,000	\$50,000	\$100,000	\$150,000
600,000	\$60,000	\$120,000	\$180,000
700,000	\$70,000	\$140,000	\$210,000

Note:

- (1) "Remuneration" refers to annual salary plus 50 percent of target bonus.

Based on their current highest average earnings and assuming the Named Executive Officers remain employed by AltaGas until age 60, the Named Executive Officers will have the number of years of pensionable service and benefit payable set out below their names:

Named Executive Officer ⁽¹⁾	David W. Cornhill	Richard M. Alexander	Dennis A. Dawson	Kent E. Stout	Marshal L. Thompson ⁽³⁾
Years of pensionable service to December 31, 2007	11.25	1.67	7.92	6.58	3.96
Accrued pension at December 31, 2007 and payable at age 60 ⁽²⁾	\$143,300	\$12,200	\$39,600	\$28,900	\$19,700
Years of pensionable service at age 60	19.42	9.33	16.50	25.83	3.96
Annual benefit payable at age 60 ⁽²⁾	\$247,400	\$68,100	\$82,600	\$113,300	\$19,700

Notes:

- (1) Patricia M. Newson and Jeffrey F. Perry are not members of the SERP.
 (2) Estimate of benefit payable includes the value of the DC Plan and Group RRSP entitlement.
 (3) Marshal L. Thompson resigned effective June 6, 2007.

The calculation of reported amounts uses actuarial assumptions and methods that are consistent with those used for calculating pension obligations and annual expense as disclosed in AltaGas' financial statements.

Government of Canada payments received (Old Age Security and Canada Pension Plan) are in addition to the payments shown in the table.

Long Term Incentive Plans

Other than the MTIP, the Trust Unit Option Plan, the Short Term Incentive Plan, the Employee Unit Purchase Savings Plan, the Group RRSP, DC Plan and SERP, AltaGas does not have any plans which provide compensation intended to serve as an incentive to Named Executive Officers for performance to occur over a period longer than one financial year.

Other Compensation

Other than as herein set forth, AltaGas did not pay any additional compensation to its Named Executive Officers in the financial year ended December 31, 2007.

Trust Unit Ownership Guideline for Officers

In recognition of the importance of ensuring an alignment of financial interests of officers with those of Unitholders, AltaGas has adopted Trust Unit ownership guidelines for officers of AltaGas effective January 1, 2004.

Under the guidelines, incumbents in the following officer positions will be expected to make reasonable efforts to achieve targeted Trust Unit ownership levels within a five-year period commencing on the later of January 1, 2004 or upon the date of formal appointment as an officer of AltaGas. The targets and Trust Units held for the Named Executive Officers are as at December 31, 2007.

Officer	Targeted Ownership (# of Trust Units)	Actual Trust Units held as at Fiscal Year End (held directly and indirectly) ⁽¹⁾
David W. Cornhill Chairman, President and Chief Executive Officer	120,000	991,732
Richard M. Alexander Executive Vice President, Chief Operating Officer and Chief Financial Officer	30,000	20,468
Kent E. Stout Vice President Corporate Resources	20,000	13,257
Jeffrey F. Perry Divisional Vice President Field Gathering and Processing	15,000	1,563
Dennis A. Dawson Vice President, General Counsel and Corporate Secretary	20,000	89,066
Marshal L. Thompson ⁽²⁾ Former Senior Vice President External Relations and Corporate Risk	30,000	22,800
Patricia M. Newson Senior Vice President	30,000	308,630

Notes:

- (1) For purposes of administering AltaGas' Trust Unit Ownership guidelines, unvested RUs and PUs count toward Trust Unit Ownership, but are not included in these totals. With the inclusion of RUs and PUs, the majority of the officers of AltaGas were at the targeted levels of Trust Unit ownership at December 31, 2007.
- (2) Marshal L. Thompson resigned effective June 6, 2007. Mr. Thompson's Trust Units held are as of his resignation date.

Other officers of AltaGas have a targeted Trust Unit ownership level of 15,000 Trust Units.

The HR Committee will periodically review unit holding levels to monitor the progress individual officers are making towards their targeted ownership levels and to encourage officers to meet and maintain those levels.

COMPENSATION OF DIRECTORS

Cash Compensation

The members of the board of directors are entitled to compensation for their services as directors of the General Partner. In the year ended December 31, 2007, the compensation for the directors, other than the directors who are also executive officers or employees of the General Partner or AltaGas, was a retainer of \$34,000 per year plus a board meeting fee of \$1,000 per meeting and reimbursement for their out-of-pocket expenses incurred in acting as a director. The Chairman of the board of directors is an executive officer of AltaGas and received no additional fees for service on the board of directors. The Lead Director receives an additional annual fee of \$60,000 for the increased workload associated with the role of Lead Director. In the year ended December 31, 2007, each director who is a chair of one of the General Partner's committees was compensated, with the chair of the Audit Committee receiving an additional annual retainer of \$10,000 and the chair of each of the other committees receiving an additional annual retainer of \$5,000. Each member of a committee receives an additional annual retainer of \$3,000 per committee. Each director who is a member of one of the General Partner's committees received a meeting fee of \$500 per meeting.

A member of the board of directors of AltaGas who is also an executive officer of AltaGas is not entitled to compensation for services rendered to AltaGas in their capacities as such. A member of the board of directors who is also an executive officer of AltaGas will instead receive compensation in his or her capacity as an executive officer of AltaGas.

	Base Retainer Fee (\$)	Board/Committee Chair Retainer Fee (\$)	Committee Retainer Fee (\$)	Board Attendance Fee (\$)	Committee Attendance Fee (\$)	Total Fees (\$)
David W. Cornhill	Nil	Nil	Nil	Nil	Nil	Nil
Allan L. Edgeworth	\$34,000	Nil	\$6,000	\$12,000	\$4,500	\$56,500
Denis C. Fonteyne	\$34,000	\$5,000	\$3,000	\$12,000	\$3,500	\$57,500
Daryl H. Gilbert	\$34,000	Nil	\$6,000	\$11,000	\$4,000	\$55,000
Robert B. Hodgins	\$34,000	\$10,000	\$3,000	\$12,000	\$5,000	\$64,000
Myron F. Kanik	\$94,000	\$10,000	Nil	\$12,000	\$4,000	\$120,000
David F. Mackie	\$34,000	Nil	\$6,000	\$12,000	\$4,000	\$56,000
M. Neil McCrank ⁽¹⁾	Nil	Nil	Nil	Nil	Nil	Nil

Note:

(1) Mr. McCrank was appointed to the board of directors on December 10, 2007.

Equity Compensation

Trust Unit Option Plan Grants and Medium Term Incentive Plan Grants

The following table sets forth certain information relating to Trust Unit Options, RUs and PUs issued to the directors during the year ended December 31, 2007.

Name	Grant Date	Securities Under Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Financial Year (%)	Exercise Price or Base Price (\$/Security) ⁽¹⁾	Market Value of Securities Underlying Options/SARS on the Date of Grant (\$/Security)	Expiration Date ⁽²⁾
Allan L. Edgeworth	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-
Denis C. Fonteyne	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-
Daryl H. Gilbert	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-
Robert B. Hodgins	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-
Myron F. Kanik	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-

Name	Grant Date	Securities Under Options/SARS Granted (#)	Percent of Total Options/SARS Granted to Employees in Financial Year (%)	Exercise Price or Base Price (\$/Security) ⁽¹⁾	Market Value of Securities Underlying Options/SARS on the Date of Grant (\$/Security)	Expiration Date ⁽²⁾
David F. Mackie	April 16, 2007	750 RUs	16.67	-	25.07	-
	Dec 10, 2007	750 RUs	14.29	-	25.02	-
M. Neil McCrank ⁽³⁾	Dec 10, 2007	20,000 Options	6.33	25.00	25.02	Dec 10, 2017
	Dec 10, 2007	750 RUs	14.29	-	25.02	-

Notes:

- (1) The base price varies with the market value of the Trust Units in the open market.
- (2) RUs and PUs do not have an expiration date. RUs vest as to one-third per year over a three-year period commencing with the year of grant, contingent upon AltaGas and the Trust achieving a threshold level of performance during each year of the vesting period while PUs will vest at the end of a three-year period commencing with the year of grant, contingent upon AltaGas and the Trust achieving a threshold level of performance during the three-year vesting period. See above under "Report on Executive and Employee Compensation – Compensation Policy – Mid Term Incentive Plan".
- (3) Mr. McCrank was appointed to the board of directors on December 10, 2007.

The following table shows the aggregate number of Trust Units acquired on exercise of Trust Unit Options during the financial year ended December 31, 2007, if any, the value realized upon exercise of the Trust Unit Options, the number of unexercised Trust Unit Options held at year-end and the year-end value of the unexercised Trust Unit Options held by independent directors.

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ⁽¹⁾ (\$)	Unexercised Options at Fiscal Year-End Exercisable / Unexercisable (##)	Value of Unexercised in-the-Money Options at Fiscal Year-End ⁽²⁾ Exercisable / Unexercisable (\$/S)
Allan L. Edgeworth	-	-	21,250/13,750	10,437.50/15,612.50
Denis C. Fonteyne	-	-	11,250/3,750	-/-
Daryl H. Gilbert	-	-	11,250/3,750	-/-
Robert B. Hodgins	-	-	21,250/13,750	10,437.50/15,612.50
Myron F. Kanik	-	-	11,250/3,750	-/-
David F. Mackie	-	-	11,250/3,750	-/-
M. Neil McCrank ⁽³⁾	-	-	6,667/13,333	9,600.50/19,199.50

Notes:

- (1) For the purpose of calculating the aggregate value realized, the exercise price of each Trust Unit Option exercised was subtracted from the closing trading price for the Trust Units on the TSX on the day on which the Trust Unit Options were exercised, and the resulting value was multiplied by the number of Trust Units obtained on exercise of Trust Unit Options. Note that all Trust Units obtained on exercise of Trust Unit Options may not have been sold, so that these values may not have been actually realized by the optionees.
- (2) For the purpose of calculating the in-the-money values of the Trust Unit Options, the exercise price of each Trust Unit Option would be subtracted from the closing price of the Trust Units on the TSX on December 31, 2007, the last trading day in the Trust's financial year ended December 31, 2007, which was \$26.44.
- (3) Mr. McCrank was appointed to the board of directors on December 10, 2007.

The directors have limited the number of Trust Unit Options reserved for grant to the independent directors to 1.0 percent of the outstanding Trust Units, including Exchangeable Units. The total number of the Trust Unit Options granted to directors at December 31, 2007 is equal to 0.26 percent of the issued and outstanding Trust Units, including Exchangeable Units.

Total Compensation

The following table sets forth the total amount of compensation paid to each of the directors for fiscal 2007.

Name	Fees Paid or Earned in Cash (\$)	Stock Awards (\$) ⁽¹⁾⁽²⁾	Option Awards (\$) ⁽¹⁾	Non-Equity Incentive Plan Compensation (\$)	Change in Pension Value (\$)	All Other Compensation (\$) ⁽³⁾	Total (\$)
Allan L. Edgeworth	56,500	10,387	36,300	-	-	-	103,187
Denis C. Fonteyne	57,500	10,387	18,900	-	-	-	86,787
Daryl H. Gilbert	55,000	10,387	18,900	-	-	-	84,287
Robert B. Hodgins	64,000	10,387	36,300	-	-	-	110,687
Myron F. Kanik	120,000	10,387	18,900	-	-	-	149,287
David F. Mackie	56,000	10,387	18,900	-	-	-	85,287
M. Neil McCrank ⁽⁴⁾	-	1,010	11,200	-	-	-	12,210

Notes:

- (1) Reflects the dollar amount recognized for financial statement reporting purposes with respect to the fiscal year in accordance with Section 3870 of the CICA Handbook. These amounts reflect the Trust's accounting expense for the awards and do not correspond to the actual value that will be recognized by the director. The assumptions used in the calculation of the amounts are described in note 2 to our consolidated financial statements for the year ended December 31, 2007 as filed on SEDAR.
- (2) Reflects RUs and PUs issued to each director pursuant to the MTIP.
- (3) Other than as herein set forth, the value of all other compensation was no greater than the lesser of \$50,000 and 10% of the total fees paid to, or earned by, each director in fiscal 2007.
- (4) Mr. McCrank was appointed to the board of directors on December 10, 2007.

Trust Unit Ownership Guideline for Directors

In recognition of the importance of ensuring an alignment of financial interests of directors with those of Unitholders, AltaGas has adopted a Trust Unit ownership guideline for directors of AltaGas effective August 2006.

Under the guideline, directors are encouraged to achieve a targeted Trust Unit ownership level of three times their annual retainer within a five-year period commencing on the later of August 9, 2006 or upon the date of formal appointment as a director of AltaGas.

Name	Targeted Ownership (# of Trust Units) ⁽¹⁾	Actual Trust Units and Exchangeable Units held as at Fiscal Year-End ⁽²⁾
Allan L. Edgeworth	3 times annual retainer	3,000
Denis C. Fonteyne	3 times annual retainer	36,300
Daryl H. Gilbert	3 times annual retainer	900
Robert B. Hodgins	3 times annual retainer	2,000
Myron F. Kanik	3 times annual retainer	43,960

Name	Targeted Ownership (# of Trust Units) ⁽¹⁾	Actual Trust Units and Exchangeable Units held as at Fiscal Year-End ⁽²⁾
David F. Mackie	3 times annual retainer	1,055,216
M. Neil McCrank ⁽³⁾	3 times annual retainer	0

Notes:

- (1) Annual retainer at December 31, 2007 was \$34,000. Targeted ownership using the December 31, 2007 Trust Unit closing price on the TSX of \$26.44 would be 3,858 Trust Units.
- (2) The information as to the Trust Units and Exchangeable Units owned includes both Trust Units beneficially owned, directly or indirectly, and Trust Units and Exchangeable Units over which control or direction is exercised, and has been furnished by each of the nominees as of December 31, 2007.
- (3) Mr. McCrank was appointed to the board of directors on December 10, 2007.

The Governance Committee periodically reviews Trust Unit holding levels to monitor the progress individual directors are making towards targeted ownership levels and to encourage directors to meet and maintain those levels.

Directors and Officers Liability Insurance

Directors and officers' insurance has been obtained for the board of directors and officers of AltaGas and its subsidiaries with a policy limit of \$40,000,000 aggregate per policy year. Under this insurance coverage, AltaGas would be reimbursed for indemnity payments made on behalf of the board of directors and officers of AltaGas subject to a deductible of \$500,000 per occurrence, which would be paid by AltaGas. The total premium paid by AltaGas for directors and officers' liability insurance during the financial year ended December 31, 2007 was \$174,000.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth information related to AltaGas' equity compensation plans for the financial year ended December 31, 2007:

Plan Category	Number of Securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by securityholders	1,330,400	\$26.34	4,185,848
Equity Compensation plans not approved by securityholders	N/A	N/A	N/A
Total	1,330,400	\$26.34	4,185,848

OTHER MATTERS

The General Partner knows of no amendment, variation or other matter to come before the Meeting other than the matters referred to in the Notice of Meeting; however, if any other matter properly comes before the Meeting, the accompanying proxy will be voted on such matter in accordance with the best judgment of the person or persons voting the proxy.

AltaGas shall provide without charge, upon request being made to AltaGas, a copy of the Trust's annual information form, together with any document, or the pertinent pages of any document, incorporated by reference therein, the Trust's most recently filed comparative annual financial statements, together with the accompanying report of the auditor, the Trust's most recently filed annual Management's Discussion and Analysis and any interim financial statements of the Trust that have been filed thereafter and the interim Management's Discussion and Analysis relating thereto. Financial information is provided in the Trust's comparative financial statements and Management's Discussion and Analysis for the year ended December 31, 2007.

Additional information relating to the General Partner, AltaGas and the Trust is available under the Trust's profile on SEDAR at www.sedar.com.

DATE: March 6, 2008.

SCHEDULE A

STATEMENT OF GENERAL PARTNER'S GOVERNANCE PRACTICES

The following table sets forth the disclosure requirements for Corporate Governance Disclosure set forth in NI 58-101F1 together with the General Partner's governance approach. In addition, where applicable the table references the requirements contained in MI 52-110 and the General Partner's compliance therewith. The board of directors believes that the General Partner's corporate governance policies and practices fully comply with the requirements of MI 52-110 and NI 58-101 and with the guidelines of NP 58-201.

1. Board of Directors																	
a.	Disclose the identity of directors who are independent. Independent directors: <table> <tr> <td>Allan L. Edgeworth</td><td>Denis C. Fonteyne</td></tr> <tr> <td>Daryl H. Gilbert</td><td>Robert B. Hodgins</td></tr> <tr> <td>Myron F. Kanik</td><td>David F. Mackie</td></tr> <tr> <td>M. Neil McCrank</td><td></td></tr> </table> This disclosure is also set forth above under "<i>Matters to be Considered at the Meeting - Election of Directors</i>".	Allan L. Edgeworth	Denis C. Fonteyne	Daryl H. Gilbert	Robert B. Hodgins	Myron F. Kanik	David F. Mackie	M. Neil McCrank									
Allan L. Edgeworth	Denis C. Fonteyne																
Daryl H. Gilbert	Robert B. Hodgins																
Myron F. Kanik	David F. Mackie																
M. Neil McCrank																	
b.	Disclose the identity of directors who are not independent, and describe the basis for that determination. David W. Cornhill, as Chief Executive Officer of the General Partner and AltaGas and a member of management, is not considered independent.																
c.	Disclose whether or not a majority of directors are independent. A majority of the directors, seven of eight, are independent within the meaning of NI 58-201.																
d.	Disclose directors' directorships in other public entities. <table> <tr> <td>David W. Cornhill</td><td>AltaGas Utility Group Inc.</td></tr> <tr> <td>Allan L. Edgeworth</td><td>Emera Inc. Pembina Pipeline Corporation</td></tr> <tr> <td>Denis C. Fonteyne</td><td>None</td></tr> <tr> <td>Daryl H. Gilbert</td><td>Crocotta Energy Inc. Falcon Oil & Gas Ltd. Globel Direct, inc. Kereco Energy Ltd. MGM Energy Corp. Nexstar Energy Ltd. Penn West Petroleum Ltd. Qwest Energy Corp. (and related entities) Qwest Investment Management Corp. (and related entities) Seaview Energy Inc. Zedi Inc.</td></tr> <tr> <td>Robert B. Hodgins</td><td>Enerflex Systems Ltd. EnerMark Inc. Fairborne Energy Ltd. MGM Energy Corp.</td></tr> <tr> <td>Myron F. Kanik</td><td>Pembina Pipeline Corporation</td></tr> <tr> <td>David F. Mackie</td><td>None</td></tr> <tr> <td>M. Neil McCrank</td><td>None</td></tr> </table>	David W. Cornhill	AltaGas Utility Group Inc.	Allan L. Edgeworth	Emera Inc. Pembina Pipeline Corporation	Denis C. Fonteyne	None	Daryl H. Gilbert	Crocotta Energy Inc. Falcon Oil & Gas Ltd. Globel Direct, inc. Kereco Energy Ltd. MGM Energy Corp. Nexstar Energy Ltd. Penn West Petroleum Ltd. Qwest Energy Corp. (and related entities) Qwest Investment Management Corp. (and related entities) Seaview Energy Inc. Zedi Inc.	Robert B. Hodgins	Enerflex Systems Ltd. EnerMark Inc. Fairborne Energy Ltd. MGM Energy Corp.	Myron F. Kanik	Pembina Pipeline Corporation	David F. Mackie	None	M. Neil McCrank	None
David W. Cornhill	AltaGas Utility Group Inc.																
Allan L. Edgeworth	Emera Inc. Pembina Pipeline Corporation																
Denis C. Fonteyne	None																
Daryl H. Gilbert	Crocotta Energy Inc. Falcon Oil & Gas Ltd. Globel Direct, inc. Kereco Energy Ltd. MGM Energy Corp. Nexstar Energy Ltd. Penn West Petroleum Ltd. Qwest Energy Corp. (and related entities) Qwest Investment Management Corp. (and related entities) Seaview Energy Inc. Zedi Inc.																
Robert B. Hodgins	Enerflex Systems Ltd. EnerMark Inc. Fairborne Energy Ltd. MGM Energy Corp.																
Myron F. Kanik	Pembina Pipeline Corporation																
David F. Mackie	None																
M. Neil McCrank	None																
e.	Disclose whether or not the independent directors hold regularly scheduled meetings at which																

non-independent directors and members of management are not in attendance. If the independent directors hold such meetings, disclose the number of meetings held since the beginning of the issuer's most recently completed financial year. If the independent directors do not hold such meetings, describe what the board does to facilitate open and candid discussion among its independent directors.

In 2007, the independent directors had six (6) regularly scheduled meetings at which the non-independent director and management were not in attendance.

f. Disclose whether or not the chair of the board is an independent director. If the board has a chair or lead director who is an independent director, disclose the identity of the independent chair or lead director, and describe his or her role and responsibilities.

David W. Cornhill is the Chairman of the board of directors and Chief Executive Officer of the General Partner and AltaGas and is not considered an independent director.

To ensure that the board of directors can function independently of management, the board of directors has appointed Myron F. Kanik, an independent director, as Lead Director. Mr. Kanik acts as Chair of the board of directors at meetings where the non-independent director and management are not in attendance. Responsibility for administering the board of directors' relationship to management has been assigned to the Governance Committee. Mr. Kanik is also chair of the Governance Committee.

See discussion of Governance Committee below.

g. Disclose the attendance record of each director for all board meetings held since the beginning of the issuer's most recently completed financial year.

See disclosure of attendance record above under "*Election of Directors*".

2. Board Mandate

a. The board of directors has the following mandate:
CONSTITUTION

The board of directors of AltaGas General Partner Inc. (the "**General Partner**") is constituted in accordance with the Articles and By-laws of the Corporation as amended from time to time and in accordance with the *Canada Business Corporations Act* (the "**Act**") as amended from time to time.

Pursuant to the delegation agreement dated May 1, 2004 among AltaGas Income Trust (the "**Trust**"), the General Partner and the Trustee (the "**Delegation Agreement**"), the board of directors of the General Partner is responsible for managing the business and affairs of the Trust.

In addition, pursuant to a unanimous shareholder agreement dated May 1, 2004 among the General Partner, AltaGas Holding Limited Partnership No. 1, AltaGas Holding Limited Partnership No. 2 and AltaGas Ltd. ("**AltaGas**") (the "**Unanimous Shareholder Agreement**"), AltaGas has granted to the General Partner the power, among other things, of the directors of AltaGas to appoint the executive officers of AltaGas and to manage, or to supervise the management of, the business and affairs of AltaGas.

MEMBERSHIP AND ORGANIZATION

The Articles of the Corporation provide that there shall be a minimum of one and a maximum of nine directors. In addition, the Articles provide that the directors may appoint one or more directors to hold office for a term expiring at the next annual meeting of the Unitholders provided that the total number so appointed may not exceed one third of the number of directors elected at the previous annual meeting of the Unitholders.

Nominations for the position of director are in accordance with the Articles and By-laws of the Corporation and the Act. Nominees for directors are initially considered and recommended by the Governance Committee of the board of directors, approved by the board of directors as a whole and elected annually by the Trustee at the direction of the Unitholders.

The board of directors must be composed of a majority of members who have been determined by the board of directors to be independent. A director is independent if the director has no relationship with the Trust, the General Partner or AltaGas which could, in the view of the board of directors, reasonably interfere with the exercise of a director's independent judgement.

The board of directors may delegate certain of their responsibilities to committees of the board of directors. The responsibilities of the committees will be set forth in a mandate for each committee, as

determined by the board of directors from time to time.

MEETINGS

- A. The board of directors shall convene at such times and places as determined by the board of directors, or as required by the By-laws or the Act. In addition, the board of directors shall convene at the request of the Chairman, the Lead Director, any officer of the General Partner or AltaGas or any director or as otherwise set forth in the By-laws.
- B. Notice of the time, date and place of each meeting of the board of directors shall be given to each director not less than 48 hours before the time when the meeting is to be held in accordance with the By-laws and the Act.
- C. A quorum of the directors at any meeting necessary for the transaction of business shall be as set forth in the By-laws.
- D. The board of directors will meet at least once annually to review long-term and strategic planning for the Trust.
- E. The independent directors will meet on a periodic basis in the absence of management and non-independent directors.

DUTIES AND RESPONSIBILITIES

- A. The board of directors has plenary power. Any responsibility not delegated to management or a committee of the board of directors remains with the board of directors.
- B. The board of directors, in accordance with the Articles, the By-laws and the Act, affirms its mandate and general power to manage and supervise the management of the business and affairs of the Trust, the General Partner and AltaGas and assumes responsibility for the overall stewardship of the Trust, the General Partner and AltaGas.
- C. In discharging its general powers and responsibilities and fulfilling its mandate, the board of directors oversees the development, adoption and implementation of the Trust's strategies and plans. In addition to its general powers and responsibilities, the Board's responsibilities include:
 - 1. Establishing a code of business ethics, encouraging a culture of ethical business conduct throughout the organization and monitoring compliance with the code of business ethics by the directors, officers and employees of the Trust and its subsidiaries;
 - 2. Participating in the Trust's strategic planning process on an annual basis, including an examination of the opportunities and risks of the business of the Trust and its subsidiaries;
 - 3. Identifying and understanding the principal risks associated with the Trust's business and reviewing and approving the implementation of systems to manage such risks;
 - 4. Overseeing management development and succession planning through the Human Resources and Compensation Committee;
 - 5. Establishing policies for communicating with Unitholders and others and for receiving comment from Unitholders and others;
 - 6. Reviewing the effectiveness of the Trust's internal control and management information systems;
 - 7. Developing the Trust's approach to governance through the Governance Committee of the board of directors; and
 - 8. The general review of the Trust's results of operations, including the evaluation of the general and specific performance of management.
- D. The board of directors is responsible for establishing policies to ensure effective, timely and non-selective communications between the Trust, its Unitholders, other stakeholders and the public. The board of directors, or the appropriate committee thereof, will review and approve the content of the Trust's major communications to Unitholders and the investing public, including the quarterly and annual reports, the information circular, the annual information form and any prospectuses that may be issued. The board of directors will establish policies for receiving communications from its Unitholders, other stakeholders and the public.

- E. The board of directors is responsible for establishing the mandates, roles and responsibilities of the Committees of the board of directors and the Chairs of each Committee and for delineating the responsibilities of the Chairman, Lead Director, President and Chief Executive Officer and management.

Discussion

The mandate of the board of directors pursuant to the *Canada Business Corporations Act* (the "CBCA") CBCA is generally to manage or supervise the management of the business and affairs of the General Partner. Pursuant to the Unanimous Shareholder Agreement the board of directors has also assumed that role in respect of AltaGas.

The board of directors sets one meeting per year for a comprehensive review and approval of the Trust's budget and plan for the Trust and its affiliates the following year. The board of directors has also established one meeting per year for a comprehensive review and approval of the overall strategic plan of the Trust and its affiliates. Management regularly provides the board of directors with operational reviews of the Trust's and its affiliates' activities. In conjunction with these reviews, the board of directors discusses various strategic planning matters and identifies business and other risks associated with the activities of the Trust and its affiliates, as it considers appropriate.

The board of directors is responsible for understanding the principal risks associated with the business of the Trust and its affiliates on an ongoing basis and management is responsible to ensure that the board of directors and its committees are kept well informed of these changing risks on a timely basis.

The board of directors considers that certain decisions are sufficiently important that management should seek prior approval of the board of directors. Such decisions include: approval of the annual capital and operating budgets and any material changes to or deviations from these budgets; acquisition or sale of significant assets, including significant commitments with industry partners; significant debt or equity financing; changes in management; all matters as required under the Declaration of Trust or the CBCA; and significant changes incorporate policies, goals or objectives.

3. Position Descriptions

- a. **Disclose whether or not the board has developed written position descriptions for the chair and the chair of each board committee. If the board has not developed written position descriptions for the chair and/or the chair of each board committee, briefly describe how the board delineates the role and responsibilities of each such position.**

The board of directors has established written mandates for the board of directors and each of the Audit, Governance, Human Resources and Compensation, and Environment, Occupational Health and Safety Committees which set out the roles and responsibilities of the board and each committee. The Governance Committee's mandate includes review of the description of the directors' duties and the division of duties between and among directors, the Chairman, the Lead Director, the Chief Executive Officer and management.

- b. **Disclose whether or not the board and CEO have developed a written position description for the CEO. If the board and CEO have not developed such a written position description, briefly describe how the board delineates the role and responsibilities of the CEO.**

The board of directors has developed and maintains a position description for the Chief Executive Officer (within the context of the requirements imposed by the Declaration of Trust, the CBCA and AltaGas' by-laws), which includes the limits on management's responsibilities. The Governance Committee's mandate includes review of the description of the directors' duties and the division of duties between and among directors, the Chairman, the Lead Director, the Chief Executive Officer and management.

The board of directors develops corporate objectives for which the Chief Executive Officer is responsible through its annual budget and strategic plan review, and otherwise as required. The Human Resources and Compensation Committee evaluates the Chief Executive Officer against those objectives and reports the results of the evaluation to the board of directors.

4. Orientation and Continuing Education

- a. Briefly describe what measures the board takes to orient new directors regarding**
(i) the role of the board, its committees and its directors, and
(ii) the nature and operation of the issuer's business.
- The Governance Committee is responsible for establishing formal orientation, development and education programs and materials for new directors.
- The General Partner does not provide formal education programs for new directors, but meetings are arranged with the Lead Director, the Chairman, the Chief Executive Officer, Chief Operating Officer, Chief Financial Officer, the Vice President, General Counsel and Corporate Secretary and other members of management to discuss the role of the board of directors, its Committees and its directors, and the nature and operation of AltaGas' business. In addition, the General Partner does provide such other orientation and information as individual directors may request.
- b. Briefly describe what measures, if any, the board takes to provide continuing education for its directors.**
- The Governance Committee is responsible for establishing formal orientation, development and education programs and materials for directors. Ongoing education of all directors is offered where a need is perceived or based on input obtained from individual directors as part of the assessment process.

5. Ethical Business Conduct

- a. Disclose whether or not the board has adopted a written code for the directors, officers and employees. If the board has adopted a written code:**
(i) disclose how a person or company may obtain a copy of the code;
(ii) describe how the board monitors compliance with the code, or if the board does not monitor compliance, explain whether and how the board satisfies itself regarding compliance with its code; and
(iii) provide a cross-reference to any material change report filed since the beginning of the issuer's most recently completed financial year that pertains to any conduct of a director or executive officer that constitutes a departure from the code.
- The board of directors has adopted a Code of Business Ethics ("COBE").
- A copy of the COBE is publicly available through the SEDAR website at www.sedar.com or on the Trust's website at www.altagas.ca or by request to the Vice President, General Counsel and Corporate Secretary.
- The board of directors monitors compliance with the COBE through reports of management to the Board Committees with responsibility for various aspects of the COBE. In addition, the Trust has established a third-party service provider hotline and website for complaints. Complaints to the third-party service provider are provided to the Chair of the Audit Committee. Employees are required to sign off annually on their understanding of COBE.
- There have not been any material change reports filed since the beginning of the Trust's most recently completed financial year that pertain to any conduct of a director or executive officer that constitutes a departure from the COBE.
- b. Describe any steps the board takes to ensure directors exercise independent judgement in considering transactions and agreements in respect of which a director or executive officer has a material interest.**
- Any director with a material interest in a transaction or agreement being considered by the board of directors is required to declare such conflict and either absent themselves from the board of directors' meeting where such transaction or agreement is being considered or abstain from voting with respect to such transaction or agreement.
- Executive Officers are to disclose any material interest in a transaction or agreement being considered by the board of directors. Such Executive Officers would not be present at the board of directors meeting at which such transaction is being considered.

c.	Describe any other steps the board takes to encourage and promote a culture of ethical business conduct. The Governance Committee is responsible for the development of the overall governance of the Trust, a continuing assessment of corporate governance matters, and to make recommendations to the board of directors regarding the General Partner's approach to corporate governance. Included in the Governance Committee's mandate is to review and make recommendations to the board of directors regarding the General Partner's approach to ethical business conduct as set forth in the COBE.
6. Nomination of directors	
a.	Describe the process by which the board identifies new candidates for board nomination. The Governance Committee's mandate includes recommending directors to the board of directors to fill vacancies on the board of directors or to be proposed for election by the Trustee, at the direction of the Unitholders. The qualifications of the new board of directors' nominees are reviewed by the Governance Committee based on criteria set by the board of directors from time to time.
b.	Disclose whether or not the board has a nominating committee composed entirely of independent directors. The Governance Committee is currently composed of Robert B. Hodgins, Myron F. Kanik and David F. Mackie, all of whom are independent directors. Myron F. Kanik is the chair of the committee and the Lead Director.
c.	If the board has a nominating committee, describe the responsibilities, powers and operation of the nominating committee. The Governance Committee's mandate includes recommending directors to the board of directors to fill vacancies on the board of directors or to be proposed for election by the Trustee, at the direction of the Unitholders. The competencies and skills of the board of directors as a whole are considered by the Governance Committee in assessing potential nominees. The qualifications of the new board of directors' nominees are reviewed by the Governance Committee based on criteria set by the board of directors from time to time. The Governance Committee's mandate includes reviewing and making recommendations as to the size of the board of directors and practices for measuring performance. Based on these recommendations, the board of directors considers its size each year when it considers the number of directors to recommend to the Unitholders for election at the annual meeting of Unitholders, taking into account the number required to carry out the board of directors' duties effectively and to maintain a diversity of view, skills and experience.
7. Compensation	
a.	Describe the process by which the board determines the compensation for the issuer's directors and officers. See the discussion under the heading "<i>Report on Employee and Executive Compensation</i>" in the Information Circular.
b.	Disclose whether or not the board has a compensation committee composed entirely of independent directors. The Human Resources and Compensation Committee currently consists of Denis C. Fonteyne, Daryl H. Gilbert, Myron F. Kanik and David F. Mackie, all of whom are independent directors. Myron F. Kanik is the chair of the committee.
c.	If the board has a compensation committee, describe the responsibilities, powers and operation of the compensation committee. The mandate of the Human Resources and Compensation Committee includes reviewing and approving corporate goals and objectives relevant to the Chief Executive Officer's compensation, evaluation of the Chief Executive Officer against those goals and objectives and making recommendations to the board of directors with respect to the Chief Executive Officer's compensation based on its evaluation, developing appropriate compensation policies for the other officers of AltaGas and for evaluating senior management performance. The Human Resources and Compensation Committee reviews executive compensation disclosure before public disclosure of this information.

- d. **If a compensation consultant or advisor has, at any time since the beginning of the issuer's most recently completed financial year, been retained to assist in determining compensation for any of the issuer's directors and officers, disclose the identity of the consultant or advisor and briefly summarize the mandate for which they have been retained. If the consultant or advisor has been retained to perform any other work for the issuer, state that fact and briefly describe the nature of the work.**

AltaGas engaged Mercer Human Resource Consulting ("Mercer") to provide specific support to it in determining compensation for AltaGas' officers during the most recently completed fiscal year. This support consisted of the development of a peer group to review executive compensation and the provision of benchmark data. Mercer was paid \$34,784 in fees for this work.

In addition to this mandate, Mercer (through a different line of business) provides general employee compensation or benefits consulting services to AltaGas.

8. Other Board Committees

- a. **If the board has other standing committees other than audit, compensation and nominating committees, identify the committee and describe their function.**

In addition to the Audit Committee, the Governance Committee and the Human Resources and Compensation Committee, the board of directors of the General Partner has established the Environment, Occupational Health and Safety Committee, which monitors and makes recommendations with respect to the environment, health and safety policies, practices and procedures of the Trust's affiliates, including AltaGas and its subsidiaries. The committee has established an environmental risk management system and monitors its operation through regular reports.

The Environment, Occupational Health and Safety Committee currently consists of David W. Cornhill, Allan L. Edgeworth and Denis C. Fonteyne, of whom Messrs. Edgeworth and Fonteyne are independent directors. Denis C. Fonteyne is the chair of the committee.

9. Assessments

- a. **Disclose whether or not the board, its committees and individual directors are regularly assessed with respect to their effectiveness and contribution. If assessments are regularly conducted, describe the process used for the assessments.**

The Governance Committee's mandate also includes establishing appropriate practices for measuring the performance and for the review of the performance of the board of directors, board of directors' committees and individual directors.

The Governance Committee conducts a formal annual assessment of the effectiveness of the board of directors, each committee of the board of directors and of individual members of the board of directors through an annual self-assessment and inquiry questionnaire. As part of the formal assessment, directors are asked for input as to areas where and how the board of directors' effectiveness could be improved, and areas where additional training or education may be beneficial. The results from the annual evaluation questionnaire are reviewed by the Governance Committee and the results are presented to the board of directors as a whole for its review.

MI 52-110 Financial Literacy

MI 52-110 Requirement	The audit committee must have a minimum of three members, each of whom must be "independent" and "financially literate" directors.
Does the General Partner Align?	Yes
Description of Approach	The CBCA, the corporate statute governing the General Partner, requires that the Audit Committee of the General Partner be composed of not less than three directors, a majority of whom are not officers or employees of the General Partner or any of its affiliates, including AltaGas. The Audit Committee complies with these requirements and the requirements of MI 52-110.

All members of the Audit Committee are “financially literate” and Allan L. Edgeworth, Daryl H. Gilbert and Robert B. Hodgins have “accounting or related financial expertise”, based on criteria established by the board of directors in accordance with MI 52-110. The board of directors has adopted the definition of “financially literate” set forth in MI 52-110.¹

The board of directors has developed written terms of reference outlining the Audit Committee’s roles and responsibilities and which provide appropriate guidance to Audit Committee members as to their duties. These terms of reference are reviewed annually by the Audit Committee. The Audit Committee reviews the annual and interim financial statements of the Trust and makes recommendations to the board of directors with respect to such statements. The Audit Committee also reviews the nature and scope of the annual audit as proposed by the auditors and management, and the adequacy of the internal accounting control procedures and systems within the Trust and its affiliates. The Audit Committee is responsible for ensuring that management has implemented an effective system of internal control and has oversight responsibility for management reporting on internal control.

The Audit Committee meets with the Trust’s auditors regularly, independent of management, and has direct communication channels with the Trust’s external and internal auditors to discuss and review specific issues as appropriate.

Audit Committee Charter

MI 52-110 Requirement	The Audit Committee must have a written charter that sets out its mandate and responsibilities.
Does the General Partner Align?	Yes
Description of Approach	The Audit Committee has a charter in place. See the Trust’s Annual Information Form for the year ended December 31, 2007 for the text of the charter.

¹ MI 52-110 defines “financial literacy” as the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Trust’s financial statements.

SEC File # 82-34911

Form 52-109F1 - Certification of Annual Filings

I, Deborah S. Stein, Vice President Finance and Chief Financial Officer, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Annual Filings*) of *AltaGas Income Trust* (the issuer) for the period ending *December 31, 2007*;
2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;
3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;
4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:
 - (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;
 - (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP;
 - (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and
5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: March 11, 2008

"Signed"

Deborah S. Stein
Vice President Finance and
Chief Financial Officer

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Form 52-109F1 - Certification of Annual Filings

I, David W. Cornhill, Chairman and Chief Executive Officer, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Annual Filings*) of *AltaGas Income Trust* (the issuer) for the period ending *December 31, 2007*;
2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;
3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;
4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:
 - (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;
 - (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP;
 - (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and
5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: March 11, 2008

"Signed"

David W. Cornhill,
Chairman and
Chief Executive Officer

SEC File # 82-34911

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ALTAGAS INCOME TRUST

Annual Information Form

For the year ended December 31, 2007

Dated: March 11, 2008

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AltaGas

Well connected.

TABLE OF CONTENTS

FORWARD-LOOKING INFORMATION	2
GLOSSARY	3
METRIC CONVERSION	6
ALTAGAS INCOME TRUST	7
TRUST STRUCTURE	8
OBJECTIVE OF THE TRUST	9
OVERVIEW AND BUSINESS STRATEGY	9
REPORTING SEGMENTS	10
ALTAGAS' GEOGRAPHIC FOOTPRINT	11
GENERAL DEVELOPMENT OF THE TRUST'S BUSINESS	12
OVERVIEW	12
HISTORICAL DEVELOPMENT	12
SIGNIFICANT ACQUISITIONS	13
BUSINESS OF THE TRUST	14
FIELD GATHERING AND PROCESSING	14
EXTRACTION AND TRANSMISSION	20
POWER GENERATION	27
ENERGY SERVICES	31
CORPORATE INVESTMENTS	33
DESCRIPTION OF THE TRUST	33
MANAGEMENT OF THE TRUST	33
THE TRUSTEE	33
DELEGATION AGREEMENT	35
ADMINISTRATION AGREEMENT	36
DECLARATION OF TRUST AND DESCRIPTION OF UNITS	37
TRUST UNITS	37
SPECIAL VOTING UNITS	37
EXCHANGEABLE UNITS	37
ISSUANCE OF UNITS	38
DISTRIBUTIONS	38
PURCHASE OF UNITS	38
TRUST UNIT REDEMPTION RIGHT	38
MEETINGS OF UNITHOLDERS	39
LIMITATION ON NON-RESIDENT OWNERSHIP	40
AMENDMENTS TO THE DECLARATION OF TRUST	41
TERM OF THE TRUST	41
TAKE-OVER BIDS	41
HOLDING TRUST	42
GENERAL	42
REDEMPTION RIGHT	42
CASH DISTRIBUTIONS	42
LIMITATION ON NON-RESIDENT OWNERSHIP	42
RESTRICTIONS ON TRANSFER OF HOLDING TRUST UNITS	42
HOLDING TRUST NOTES	43
MEETINGS OF HOLDING TRUST UNITHOLDERS	44
GENERAL PARTNER	44
DIRECTORS AND OFFICERS	44
UNANIMOUS SHAREHOLDER AGREEMENT	47
ALTAGAS LTD	48
DIRECTORS AND OFFICERS	48
RISK FACTORS	50
RISKS RELATING TO THE TRUST AND THE UNITS OF THE TRUST	50
RISKS INHERENT IN THE TRUST'S OPERATING ENTITIES	54
ENVIRONMENTAL REGULATION	57
DISTRIBUTIONS	58
DISTRIBUTION REINVESTMENT PLAN	59
MARKET FOR SECURITIES	60
SELECTED CONSOLIDATED FINANCIAL INFORMATION	61
CREDIT AND STABILITY RATINGS	61

MATERIAL CONTRACTS.....	62
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	63
LEGAL PROCEEDINGS.....	63
INTERESTS OF EXPERTS.....	63
ADDITIONAL INFORMATION	63
TRANSFER AGENTS AND REGISTRARS	63
EFFECTIVE DATE	63
SCHEDULE A: AUDIT COMMITTEE MANDATE.....	A-1

All dollar amounts in this Annual Information Form are in Canadian dollars unless otherwise stated.

FORWARD-LOOKING INFORMATION

This Annual Information Form, including the documents incorporated by reference, contains forward-looking statements. When used in this Annual Information Form, including the documents incorporated by reference, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this Annual Information Form and the documents incorporated by reference contain forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties, including without limitation, changes in market, competition, governmental or regulatory developments, and general economic conditions and the other factors discussed under the heading "Risk Factors" in this Annual Information Form. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this Annual Information Form, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Annual Information Form as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this Annual Information Form, should not be unduly relied upon. Such statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference are expressly qualified by this cautionary statement.

Financial outlook information contained in this Annual Information Form about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this Annual Information Form should not be used for purposes other than for which it is disclosed herein.

GLOSSARY

In this Annual Information Form, unless the context otherwise requires, the following terms have the indicated meanings. A reference to an agreement means the agreement as amended, supplemented or restated from time to time.

"Administration Agreement" means the administration agreement dated May 1, 2004 among the Trust, the General Partner, AltaGas Ltd. as administrator, Holding Trust, AltaGas LP #1 and AltaGas LP #2 as described under "Management of the Trust – Administration Agreement";

"AESO" means Alberta Electric System Operator;

"AltaGas" means AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership and the other operating affiliates of the Trust;

"AltaGas LP #1" means AltaGas Holding Limited Partnership No. 1;

"AltaGas LP #1 B units" means Class B limited partnership units of AltaGas LP #1;

"AltaGas LP #2" means AltaGas Holding Limited Partnership No. 2;

"AltaGas LP #2 B units" means Class B limited partnership units of AltaGas LP #2;

"AltaGas Services" or "ASI" means AltaGas Services Inc., a predecessor by amalgamation to AltaGas Ltd.;

"Arrangement" means the arrangement, under the provisions of section 192 of the CBCA, involving, among others, AltaGas Services, the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, pursuant to which the business of AltaGas Services was reorganized into an income trust effective May 1, 2004;

"ASTC Partnership" or "ASTC" means ASTC Power Partnership;

"Balancing Pool" means the Alberta governmental agency established to manage unsold PPAs from the original PPA auction, and which serves as a liability backstop for all PPAs;

"Bankruptcy Act" means the *Bankruptcy and Insolvency Act* (Canada);

"Bbls" means stock tank barrels of ethane and NGLs, expressed in standard 42 U.S. gallon barrels or 34.972 imperial gallon barrels;

"Bbls/d" means Bbls per day;

"Bcf" means 1,000,000 Mcf of natural gas;

"Bcf/d" means Bcf per day;

"BMWLP" means Bear Mountain Wind Limited Partnership, a limited partnership formed under the laws of the Province of British Columbia;

"Board of Directors" means the board of directors of the General Partner, as from time to time constituted;

"Boston Bar Partnership" means Boston Bar Limited Partnership;

"BPA" means the Balancing Pool Administrator;

"Cash Flow of the Trust" means for, or in respect of, any Distribution Period: (i) all cash amounts which are received by the Trust for, or in respect of, the Distribution Period, including, without limitation, interest, dividends, distributions, proceeds from the disposition of securities, returns of capital and repayments of indebtedness; plus (ii) the proceeds of any issuance of Trust units or any other securities of the Trust, net of the expenses of distribution, and, if applicable, the use of proceeds of any such issuance for the intended purposes; less the sum of (iii) all amounts which relate to the redemption of Trust units and which have become payable in cash by the Trust in the Distribution Period and any expenses of the Trust in the Distribution Period; and (iv) any other amounts (including taxes) required by law or the Declaration of Trust to be deducted, withheld or paid by or in respect of the Trust in such Distribution Period;

"CBCA" means the *Canada Business Corporations Act*, R.S.C. 1985, c. C 44, as amended from time to time, including the regulations from time to time promulgated thereunder;

"CBM" means coal bed methane;

"Closing Market Price" means: (i) an amount equal to the closing price of the Trust units if there was a trade on the date on which Trust units were tendered for redemption and the exchange or market provides a closing price; (ii) an amount equal to the average of the highest and lowest prices of the Trust units on the date on which the Trust units were tendered for redemption if there was trading and the exchange or other market provides only the highest and lowest prices of Trust units traded on a particular day; or (iii) the average of the last bid and last ask prices if there was no trading on the date;

"Committee" means the Audit Committee of the Board of Directors;

"Declaration of Trust" means the declaration of trust dated as of March 26, 2004 between the settlor and the Trustee, pursuant to which the Trust was created, as from time to time amended, supplemented or restated;

"DBRS" means DBRS Limited;

"Delegation Agreement" means the delegation agreement dated May 1, 2004 among the Trust, the General Partner and the Trustee described under "Management of the Trust – Delegation Agreement";

"Distribution Period" means each calendar month, or such other periods as may be determined from time to time by the General Partner on behalf of the Trustee from and including the first day thereof and to and including the last day thereof;

"ECNG Energy" means ECNG Energy L.P.;

"EDS" means Ethylene Delivery System;

"EEEP" means the Edmonton Ethane Extraction Plant;

"ERCB" means the Alberta Energy Resources Conservation Board;

"Exchangeable units" means AltaGas LP #1 B units and AltaGas LP #2 B units, if any;

"Exempt Plans" means, collectively, trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans and registered disability savings plans, each as defined in the Tax Act;

"General Partner" means AltaGas General Partner Inc., a direct wholly owned subsidiary of the Trust and the general partner of AltaGas LP #1, AltaGas LP #2, AltaGas Limited Partnership, PremStar and ECNG Energy;

"GJ" means gigajoule or 1,000,000,000 joules;

"GJ/d" means GJ per day;

"GreenWing" means GreenWing Energy Development Limited Partnership;

"GWh" means gigawatt-hour or 1,000,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"Harmattan Complex" means the Harmattan natural gas extraction plant and associated facilities;

"Holding Declaration of Trust" means the declaration of trust dated as of March 26, 2004 between the Trust, as settlor, and the Holding Trust Trustee, pursuant to which Holding Trust was created, as from time to time amended, supplemented or restated;

"Holding Trust" means AltaGas Holding Trust, an unincorporated investment trust, all of the beneficial interests of which are owned by the Trust;

"Holding Trust Note Indenture" means the agreement dated as of March 26, 2004 between Holding Trust and Computershare Trust Company of Canada, as note trustee, pursuant to which Holding Trust Notes have been, and may in the future be, issued by Holding Trust, as from time to time amended, supplemented or restated;

"Holding Trust Notes" means the unsecured subordinated notes issued pursuant to the Holding Trust Note Indenture and described in greater detail under "Holding Trust – Holding Trust Notes";

"Holding Trust Trustee" means AltaGas Holding Trust Corp., as initial trustee of Holding Trust;

"iQ2" means iQ2 Power Corp.;

"JFP" means Joffre Feedstock Pipeline;

"Joffre Extraction Plant" means the Joffre extraction plant and related facilities;

"km" means kilometre;

"m³" means a cubic metre of natural gas at standard conditions of measurement;

"Market Price" means an amount equal to the simple average of the closing price of the Trust units for each of the trading days on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust units traded on a particular day, the market price shall be an amount equal to the simple average of the highest and lowest prices for that trading day if there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days before the applicable date, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the bid and ask prices for each day on which there was no trading; the weighted average trading price of the Trust units for each day that there was trading if the exchange or market provides a weighted average trading price; and the average of the highest and lowest prices of the Trust units for each day that there was trading, if the market provides only the highest and lowest prices of Trust units traded on a particular day;

"MBbls" means 1,000 Bbls;

"Mcf" means a thousand cubic feet of natural gas at standard imperial conditions of measurement;

"Mcf/d" means Mcf per day;

"Mm" means millions;

"Mmcf" means a million cubic feet of natural gas at standard conditions of measurement;

"Mmcf/d" means Mmcf per day;

"MW" means megawatt; one MW is 1,000,000 watts; the watt is the basic electrical unit of power;

"MWh" means megawatt-hour or 1,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"NGL" or "NGLs" means natural gas liquids, which includes primarily propane, butane and pentanes plus;

"Plan" means the Premium DistributionTM, Distribution Reinvestment and Optional Unit Purchase Plan of the Trust;

"Pool" means the Alberta Power Pool;

"PPA" means power purchase arrangement;

"PremStar" means PremStar Energy Canada Limited Partnership;

"Provident" means Provident Energy Trust;

"RAPP" means the rolling 30-day average Pool price of electricity in Alberta;

"Rep Agreements" mean the Representation, Management and Processing Agreements at the Harmattan Complex;

"RET Complex" means the three interconnected processing facilities and related gathering systems located at Retlaw, Enchant and Turin in southern Alberta acquired effective January 10, 2008 with Taylor;

"S&P" means Standard & Poor's, a division of The McGraw-Hill Companies, Inc.;

"Special Voting Unit" means the special voting unit of the Trust issued by the Trust and deposited with the Voting and Exchange Trustee to which is attached that number of voting rights (each such voting right being equal to the voting rights attached to one Trust unit) equal to the number of outstanding Exchangeable units held, other than by the Trust and its affiliates;

"Tax Act" means the *Income Tax Act* (Canada), including the regulations thereunder as amended from time to time;

"Taylor" means Taylor NGL Limited Partnership, a limited partnership created pursuant to the laws of Alberta;

"**Tcf**" means 1,000,000,000 Mcf;

"**TransAlta**" means TransAlta Utilities Corporation;

"**TransCanada**" means TransCanada Energy Ltd.;

"**Trust**" means AltaGas Income Trust and, where appropriate, includes its affiliates;

"**Trust units**" means trust units of the Trust;

"**Trust options**" means options to acquire Trust units granted pursuant to AltaGas' trust unit option plan;

"**Trustee**" means Computershare Trust Company of Canada, as initial trustee pursuant to the Declaration of Trust;

"**TSX**" means the Toronto Stock Exchange;

"**Unanimous Shareholder Agreement**" means the agreement entered into on May 1, 2004 among the General Partner, AltaGas LP #1, AltaGas LP #2 and AltaGas Ltd. pursuant to which AltaGas Ltd. granted to the General Partner the powers of the directors of AltaGas Ltd. to manage, or supervise the management of, the business and affairs of AltaGas Ltd., as from time to time amended, supplemented or restated as described under "General Partner – Unanimous Shareholders Agreement";

"**Unit**" or "**units**" means Trust units and Exchangeable units;

"**unitholders**" means the holders of Trust units and Exchangeable units;

"**Utility Group**" means AltaGas Utility Group Inc.;

"**Voting and Exchange Trust Agreement**" means the agreement dated May 1, 2004 among the Trust, AltaGas LP #1, AltaGas LP #2 and the Voting and Exchange Trustee, as from time to time amended, supplemented or restated;

"**Voting and Exchange Trustee**" means Computershare Trust Company of Canada, as initial trustee under the Voting and Exchange Trust Agreement, or such other person as becomes the trustee under the Voting and Exchange Trust Agreement in accordance with such agreement;

"**WCSB**" means Western Canada Sedimentary Basin; and

"**Younger Extraction Plant**" means the Younger extraction plant and related facilities.

METRIC CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply by	To Convert From	To	Multiply By
Mcf	cubic metres	28.174	metres	feet	3.281
cubic metres	cubic feet	35.494	miles	kilometres	1.609
Bbls	cubic metres	0.159	kilometres	miles	0.621
cubic metres	Bbls	6.290	acres	hectares	0.405
tonnes	long tons	0.984	hectares	acres	2.471
feet	metres	0.305	gigajoule	Mcf	0.9482

ALTAGAS INCOME TRUST

AltaGas Income Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust. See "Declaration of Trust and Description of Units". The Trust indirectly holds all of the assets, liabilities and businesses formerly owned by AltaGas Services. AltaGas Services was incorporated on August 30, 1993 under the CBCA as 2950341 Canada Ltd. and commenced operations on April 1, 1994. Effective May 1, 2004 the business of AltaGas Services was reorganized pursuant to the Arrangement and holders of common shares of AltaGas Services received Trust units and/or Exchangeable units in exchange for their common shares. AltaGas Services became an indirect subsidiary of the Trust and was amalgamated to form AltaGas Ltd.

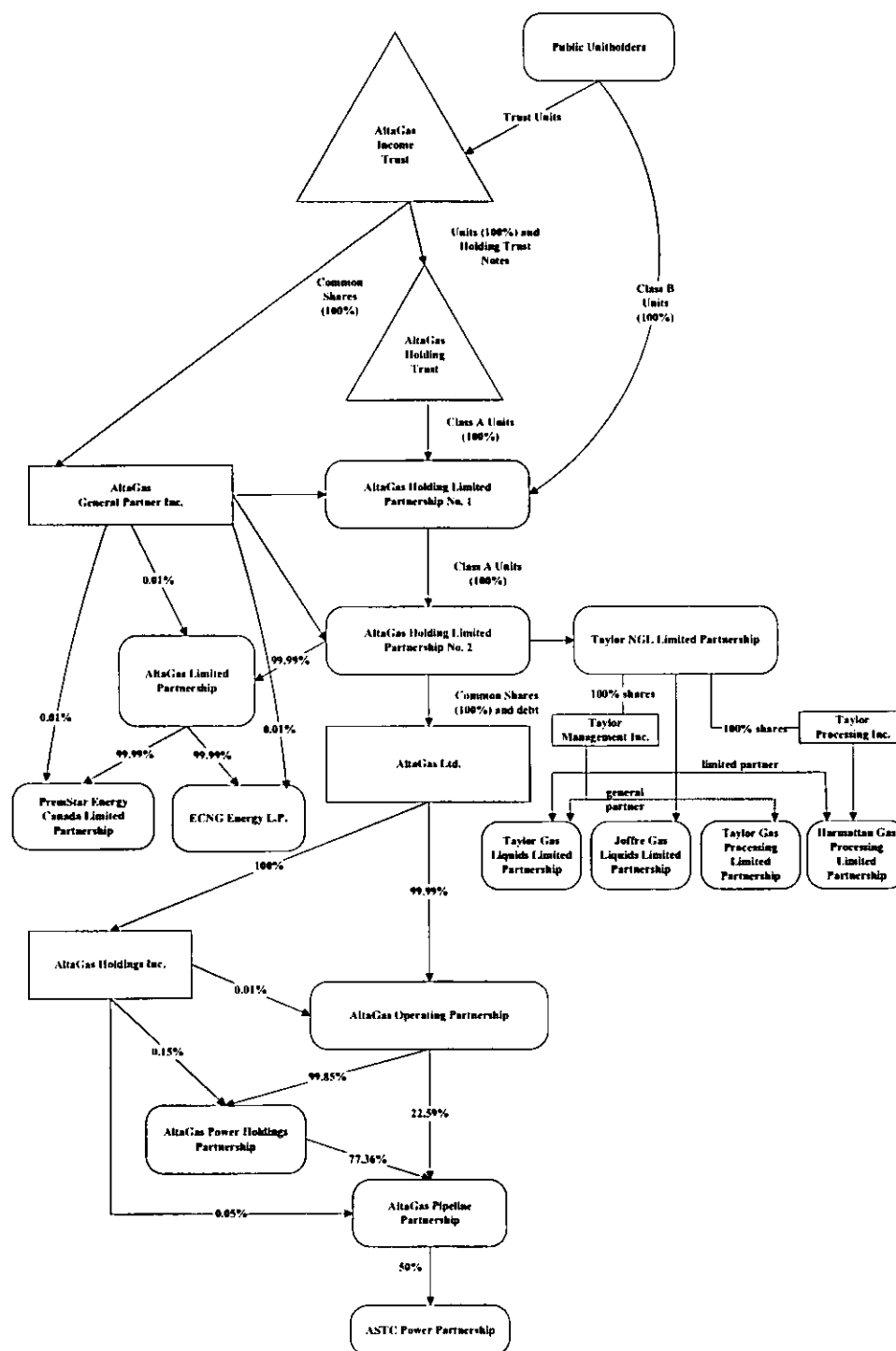
At December 31, 2007 the Trust had 56,057,438 outstanding Trust units and 2,040,456 outstanding Exchangeable units consisting entirely of AltaGas LP #1 B units. On November 29, 2007 the Trust made the offer to acquire all of the outstanding limited partnership units of Taylor. On January 10, 2008 the Trust completed the Taylor acquisition. See "Historical Development – Significant Acquisitions".

The Trust's fiscal year-end is December 31 and references in this Annual Information Form to particular years mean the Trust's fiscal years unless otherwise indicated.

The head and principal office of the Trust is located at 1700, 355 – 4th Avenue S.W., Calgary, Alberta, T2P 0J1.

TRUST STRUCTURE

The Trust and its material affiliates are shown in the following chart. The chart reflects the acquisition of Taylor and its affiliates on January 10, 2008. See "General Description of the Trust's Business – Significant Acquisitions".



- (1) The Exchangeable units are exchangeable for Trust units at the option of the holder on a one-for-one basis, are entitled to vote with unitholders and are entitled to the same cash payments per Exchangeable unit as the cash distributions made on a Trust unit. See "Declaration of Trust and Description of Units".
- (2) The Trust, Holding Trust and each of the partnerships, other than Taylor, are established under the laws of Alberta. Each of the General Partner, AltaGas Ltd. and AltaGas Holdings Inc. is a corporation incorporated or formed by amalgamation under the CBCA. Taylor was established under the laws of Ontario. Each of Taylor Processing Inc. and Taylor Management Inc. is a corporation incorporated under the *Business Corporations Act* (Alberta).

OBJECTIVE OF THE TRUST

The objective of the Trust is to grow and operate its businesses, indirectly through its operating affiliates, in a manner that builds long-term value and delivers stable results to unitholders. The Trust's objectives, through its operating affiliates, are to:

- Maximize the profitability and long-term value of its existing infrastructure and services;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee and margin-based contract terms and with minimal or managed exposure to commodity prices;
- Grow its gas and power infrastructure and related services through consolidations, expansions and acquisitions in Canada and the northern United States;
- Focus on projects that are accretive to earnings and cash flow with the appropriate risk and return balance;
- Diversify infrastructure by fuel source, contractual terms, exposure to industry cycles and geographic location;
- Focus on expanding its clean energy footprint such as wind and hydroelectric power generation as well as natural gas-fired generation;
- Generate green credits through technology such as acid gas injection and renewable projects to decrease environmental impacts and hedge against environmental costs; and
- Maintain the Trust's investment-grade credit ratings.

The Trust strives to provide unitholders with stable and growing cash distributions. The Trust employs a strategy to provide unitholders with a competitive annual cash-on-cash yield by making monthly cash distributions that are supported by a sound financial strategy and strong business performance.

OVERVIEW AND BUSINESS STRATEGY

AltaGas is a gas and power infrastructure business with physical links along the energy value chain, operating experience that has a strong track record of achieving efficiency, reliability and profitability of its assets, knowledge of the markets it serves and the financial discipline to create long-term value for its investors. AltaGas is focused on maximizing the profitability and long-term value of its current assets and growing its energy infrastructure business through the acquisition and development of assets and services that are linked to its existing business.

The gas business comprises gathering and processing assets which include natural gas gathering pipelines and processing facilities. The gathering systems move natural gas from producing wells to processing facilities and the processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation. The processing assets also include ethane and NGL extraction and field fractionation facilities. Extraction plants process the natural gas to extract and recover ethane, NGLs, industrial grade CO₂ and frac oil. The gas business also includes natural gas and NGL transmission pipelines. Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. Another key component of the AltaGas gas business is the ability to use its market knowledge and expertise to optimize the assets to create value. AltaGas provides energy consulting and supply management services to non-residential end-users, buys and resells energy, gas transportation and storage, and markets gas for producers to further enhance value by optimizing the infrastructure.

The power business includes 353 MW of coal-fired base-load generation acquired under PPAs. AltaGas' power generation portfolio also includes the Bear Mountain Wind Park currently under construction near Dawson Creek, British Columbia, which will have a capacity of approximately 100 MW. The portfolio also includes 25 MW of gas-fired peaking capacity under a capital lease and a further 14.4 MW of gas-fired peaking capacity which is currently being installed. AltaGas has an interest in a 7-MW run-of-river hydroelectric generation capacity through a 25 percent interest in the Boston Bar Partnership acquired as part of the acquisition of Taylor (see "General Development of the Trust's Business – Significant Acquisitions"). As part of the Taylor acquisition, AltaGas also acquired two 10-MW run-of-river projects currently under development and in February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. Together, these projects provide AltaGas with the potential to develop approximately 70 MW of hydroelectric power generation in British Columbia. AltaGas also has an interest through GreenWing to develop wind power and gas-fired power generation.

AltaGas' vision is to become the leading Canadian energy infrastructure company with a focus across Canada and the northern United States, by capitalizing on its solid underlying business, operational expertise and financial strength. To achieve its vision, AltaGas will focus on increasing the value and profitability of its existing assets and on growing and diversifying through development and acquisition of gas and power infrastructure.

The Trust's strategy is to deliver sustainable and increasing earnings and cash flow from its existing assets as well as from the growth and diversification of its business. It seeks to achieve this by linking the operating experience of its gas and power business with its energy market knowledge and financial discipline and strength. AltaGas expects the growth in its business to be evenly split between gas and power over the long term. The Trust also seeks to enhance value by providing value-added services along the energy value chain of gathering, processing, transporting and marketing of natural gas and the generation and sale of electricity.

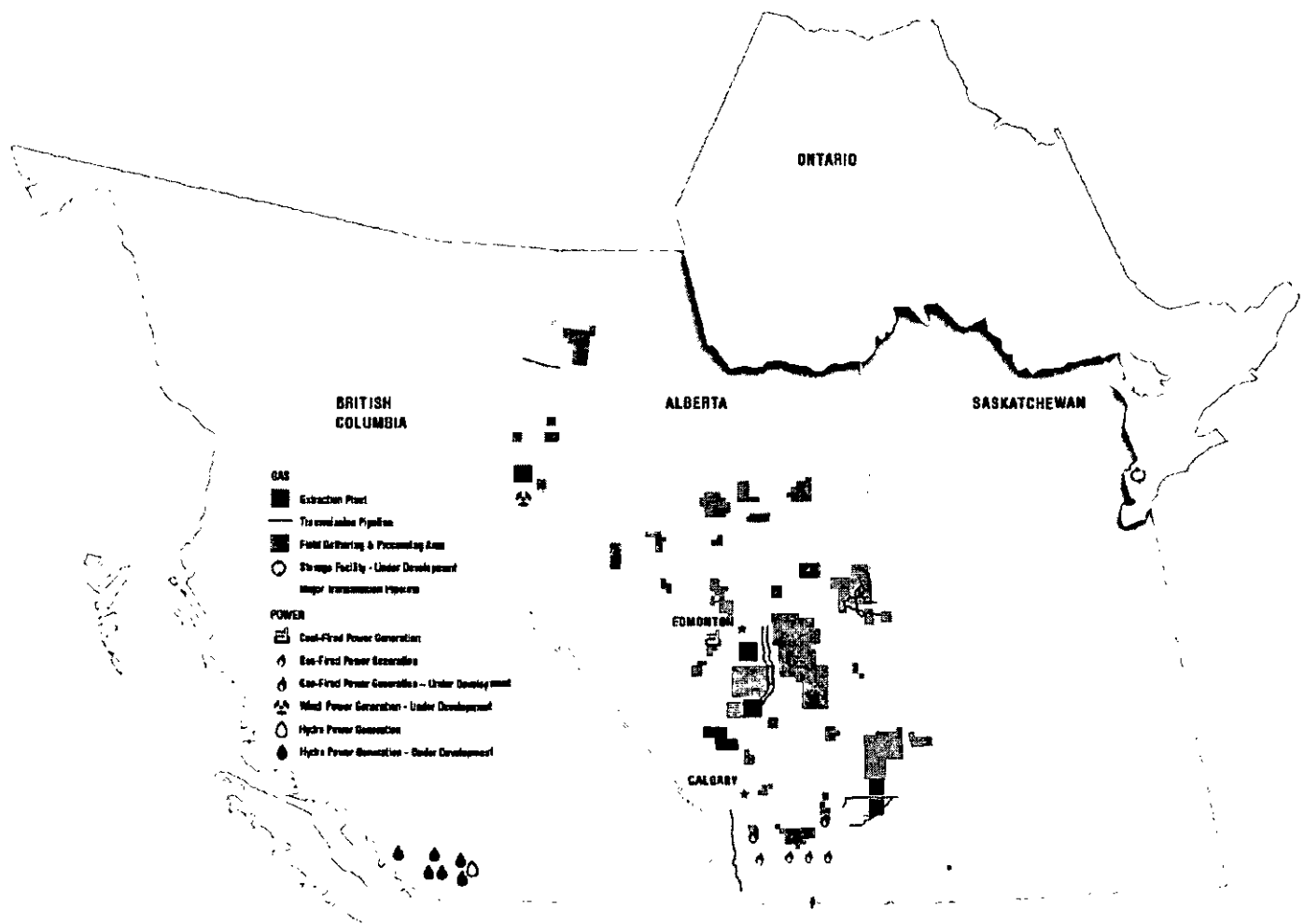
By positioning the Trust strategically along the energy value chain, AltaGas links energy producers to energy users. AltaGas pursues opportunities that offer strong financial returns and growth potential and identifies, evaluates and targets opportunities that are accretive to earnings and cash flow and provide the appropriate balance between risk and return.

REPORTING SEGMENTS

At December 31, 2007 the Trust reported consolidated financial and operating results on the basis of five segments:

- The Field Gathering and Processing segment includes natural gas gathering pipelines and processing facilities as well as AltaGas' investments in businesses ancillary to the field gathering and processing business:
 - Gathering systems move natural gas from producing wells to processing facilities;
 - Processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation;
- The Extraction and Transmission segment consists of AltaGas' interests in ethane and NGL extraction plants and natural gas and NGL transmission systems:
 - Extraction plants process the natural gas to extract and recover ethane, NGLs, CO₂ and frac oil;
 - Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines;
- The Power Generation segment consists of AltaGas' interests in coal-fired base-load generation and gas-fired peaking capacity. The segment also includes the Bear Mountain Wind Park currently being constructed and other renewable energy projects that AltaGas is seeking to develop. AltaGas acquired an interest in a 7-MW run-of-river hydroelectric project through its acquisition of Taylor;
- The Energy Services segment consists of two main businesses: energy management services and gas services:
 - The energy management business provides energy consulting and supply management services and arranges gas and power supply for non-residential end-users;
 - The gas services business buys and resells natural gas, transportation and storage;
 - The segment included a small portfolio of oil and natural gas producing assets which were sold in 2007; and
- The Corporate segment includes the cost of providing services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities.

ALTAGAS' GEOGRAPHIC FOOTPRINT



GENERAL DEVELOPMENT OF THE TRUST'S BUSINESS

OVERVIEW

AltaGas transports, processes, generates and sells energy to create value. AltaGas:

- Physically gathers, processes and transports natural gas;
- Extracts ethane and NGLs from natural gas and transports NGLs;
- Provides energy consulting and supply management services and arranges gas and power supply for non-residential end-users; and
- Markets natural gas, NGLs and electrical power and generates power through the dispatch of gas-fired generating units.

HISTORICAL DEVELOPMENT

The Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust effected on May 1, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly owned by AltaGas Services.

ASI commenced operations on April 1, 1994 with a team of 20 people with experience in the natural gas industry. The founding vision was to build a major Canadian natural gas midstream business combining a portfolio of natural gas-related services with long-life assets to grow net income. The concept of a distinct, full-service midstream business was unique in Canada at the time. ASI commenced operations with two major contracts to provide transportation, regulatory and gas management services. The revenue generated from these contracts during 1994 and 1995, together with private placement equity financings, provided the funds for ASI to establish its midstream asset base and make the transition from a consulting services company to a midstream operating company.

The nature of AltaGas' participation in the midstream industry evolved from holding primarily service contracts and non-operated investments to include fully-operated natural gas facilities of which AltaGas owns 100 percent or in which it has a controlling interest.

In late 2001 ASI entered the power business by purchasing 353 MW of power output from two coal-fired power generation units in the province of Alberta under long-term PPAs. In 2003 another PPA for an additional 100 MW of coal-fired power output was purchased under a three-year power contract with the Balancing Pool in Alberta, which terminated in March 2006. In 2004, 25 MW of gas-fired peaking capacity was acquired under a long-term capital lease arrangement.

In late 2004 AltaGas significantly expanded its Energy Services segment into Ontario and further into B.C. with the acquisition of substantially all of the assets and liabilities of PremStar Energy Canada Ltd. and its subsidiaries ECNG Inc. and Energistics Group Inc. by AltaGas affiliates PremStar and ECNG Energy. The businesses of PremStar Energy Canada Ltd. and its subsidiaries were integrated with AltaGas, but the trade names PremStar and ECNG continued to be used within the Energy Services segment. As of January 1, 2007 ECNG Limited Partnership changed its name to ECNG Energy L.P., and AltaGas began providing energy management services under the brand name ECNG Energy.

On November 3, 2005 AltaGas further expanded its Energy Services segment through the acquisition of substantially all of the assets and liabilities of iQ2. As a result of the acquisition of this business, AltaGas purchases power and gas for resale to agricultural, industrial and commercial customers in Alberta.

On November 17, 2005 AltaGas completed the spin-out of its Natural Gas Distribution segment into a separate, publicly traded company, AltaGas Utility Group Inc. The common shares of Utility Group commenced trading on the TSX at market opening November 17, 2005 under the symbol AUI. The Trust initially held 26.7 percent of Utility Group, but following a special distribution of Utility Group common shares to Trust unitholders on September 17, 2007, currently holds 1,606,594 common shares, or 19.6 percent of Utility Group's total issued and outstanding common shares.

In 2005 AltaGas invested \$50.8 million in growth capital in the Field Gathering and Processing segment to add new and expand existing infrastructure in order to meet growing producer demand in AltaGas' operating areas. This investment included a 14 Mmcfd expansion at Windfall and a 31 Mmcfd expansion at Marten Creek, as well as the acquisition of the 24 Mmcfd Blair Creek gas processing plant in late 2005.

In 2006 AltaGas invested \$53.3 million in growth capital in the Field Gathering and Processing segment. The 20 Mmcfd Princess sour gas plant went into service in 2006. Effective July 1, 2006 AltaGas' interest in the Pouce Coupe plant increased to 76.75 percent from 40.78 percent. The acquisition of the new 10 Mmcfd Clear Hills sour gas plant on September 25, 2006 increased AltaGas' processing capability in a highly prospective area that is already served by the

15 Mmcfd Clear Prairie plant that was constructed in 2005 and went into service in 2006. Additionally, the expansion of the Prairie River gas facility in August increased throughput capability at that plant by up to 10 Mmcfd.

In 2006 AltaGas announced strategic partnerships for the purpose of developing renewable power projects. In July 2006 AltaGas announced that BMWLP's Bear Mountain Wind Park had been selected as a successful bidder in the BC Hydro Fiscal 2006 Open Call for Power.

In 2007 AltaGas invested \$23.3 million in growth capital in the Field Gathering and Processing segment. The 10 Mmcfd Acme CBM processing facility went into service in November 2007. In addition, AltaGas acquired the 5 Mmcfd Corbett Creek processing facility and gathering lines in an area of significant CBM production. AltaGas also entered into a contract to acquire a new 15 Mmcfd natural gas gathering line that is currently under construction in northwest Alberta to connect the Clear Prairie gas processing facility to the Square Creek area, 250 km northwest of Grande Prairie, Alberta.

In April 2007 AltaGas acquired an additional 14.4 MW of power generation capacity, comprising six 2.4-MW Superior gas-fired units which will be installed at the Bantry and Parkland field gathering and processing sites with access to natural gas supply and the electrical grid. The facilities will be integrated into ongoing operations and are expected to be in service in mid-2008.

Effective June 1, 2007 AltaGas sold Cedar Energy Partnership to a private energy company for approximately \$12 million plus one million warrants of the purchaser with a three-year term ending June 1, 2010. Effective July 31, 2007 AltaGas sold its one-third interest in the Ikhlil Joint Venture to Utility Group for \$9 million. The sale of Cedar Energy Partnership and the Ikhlil Joint Venture was part of AltaGas' plan to divest non-core oil and gas production assets.

In September 2007 AltaGas purchased a 50 percent interest in the Sarnia Airport Storage Pool Project. The Sarnia natural gas storage project represents AltaGas' first investment in natural gas infrastructure in Ontario. Once developed, the Sarnia Airport Storage Pool Project is expected to have 5.3 Bcf of working capacity and deliverability of approximately 52 Mmcfd. The project is targeted to be in full operation by mid-2009.

In 2007 BMWLP continued to make progress with the development of the Bear Mountain Wind Park. The wind park is anticipated to comprise 34 turbines with a total capacity of approximately 100 MW of electricity. BMWLP signed an agreement with Enercon GmbH, a leading turbine manufacturer based in Germany, to provide and install the turbines for the wind park under a fixed-price engineering, procurement and construction contract and to operate and maintain the turbines under a long-term service agreement. Construction of the wind park began in December 2007 and it is scheduled to be in service in November 2009. In August 2007 AltaGas purchased Aeolis Wind Power Corporation's interest in BMWLP with the result that BMWLP is now wholly owned by AltaGas.

SIGNIFICANT ACQUISITIONS

On November 29, 2007 the Trust, indirectly through AltaGas LP #1, offered to acquire all of the outstanding limited partnership units of Taylor NGL Limited Partnership on the basis of, at the election of the holder: (a) \$11.20 in cash, subject to a maximum of \$245 million (subject to adjustment); (b) 0.42 of a Trust unit; or (c) a combination of Exchangeable units and Trust units. The total number of Trust units and Exchangeable units available was limited, subject to adjustment, to 8,000,000 and the total number of Exchangeable units available was limited, subject to adjustment, to 1,875,000. On January 10, 2008 AltaGas LP#1 completed the acquisition of Taylor for the aggregate purchase price of \$598.7 million, including \$256.3 million of cash and 7.7 million Trust units (including 0.2 million Exchangeable units) valued at \$198.9 million for all the outstanding limited partnership units of Taylor not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$11.0 million in transaction costs. The Taylor acquisition increased extraction capacity by 1,040 Mmcfd, added 140,000 Bbls/d in transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing segment's capacity by 150 Mmcfd. In addition, the Power Generation segment increased with the 25 percent ownership interest in the 7 MW Boston Bar Partnership power plant and acquisition of 20 MW of hydroelectric generation under development.

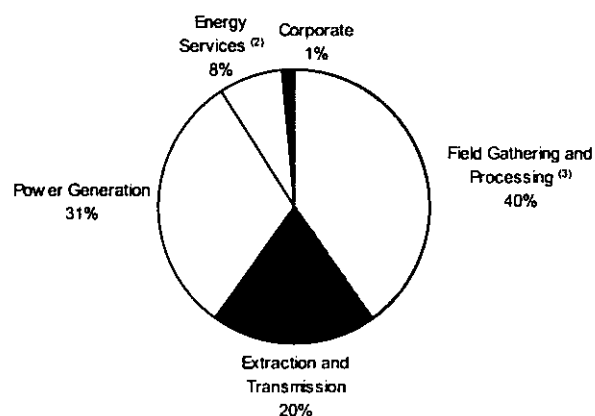
For further information in relation to the acquisition of Taylor, see the Trust's business acquisition report dated March 3, 2008, which is hereby incorporated by reference and which has been filed on SEDAR at www.sedar.com.

Unless expressly stated, all numbers in this Annual Information Form are as at December 31, 2007 and exclude the acquisition of Taylor.

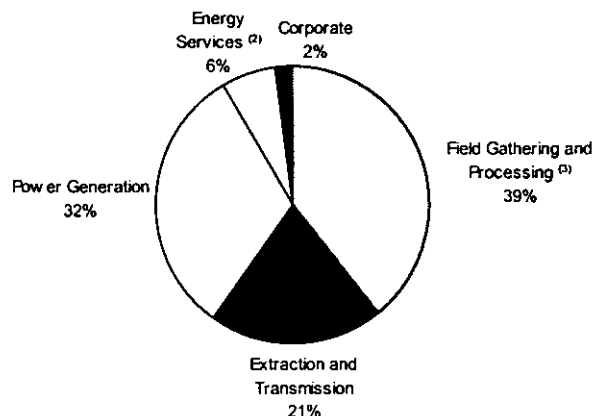
BUSINESS OF THE TRUST

The Trust's net revenue for the 12-month period ended December 31, 2007 was \$324.0 million compared to \$318.9 million for the 12-month period ended December 31, 2006.

Net Revenue by Segment for 2006 ⁽¹⁾



Net Revenue by Segment for 2007 ⁽¹⁾



(1) Net revenue is gross revenue less the cost of commodities purchased for resale and shrinkage.

(2) Includes oil and natural gas production until May 31, 2007. See "General Development of the Trust's Business – Historical Development".

(3) Field Gathering and Processing includes AltaGas' investments in AltaGas Energy Solutions Inc. and, until July 31, 2007, the Ikhil Joint Venture.

FIELD GATHERING AND PROCESSING

The Field Gathering and Processing segment contributed net revenue of \$127.4 million for the year ended December 31, 2007, representing approximately 39 percent of the Trust's total net revenue before intersegment eliminations.

The Field Gathering and Processing segment consists of 77 gathering and processing facilities in 30 operating areas located in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets. This includes the RET Complex. Subsequent to the acquisition of Taylor, AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, including 359 Mmcfd of sour gas capacity. AltaGas operates 74 of its 77 facilities.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmcfd, which distinguishes it from most of its competitors in western Canada.

The Field Gathering and Processing segment's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie-ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Field Gathering and Processing - Business Strategy

The Field Gathering and Processing segment provides safe and reliable gathering and processing and ancillary services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share, servicing Alberta's future CBM production and moving westward to capitalize on increased exploration and drilling activities. While the WCSB is considered to be a maturing basin, AltaGas remains confident in the long-term demand for natural gas, strong natural gas prices and improvements in exploration and drilling technology, and hence the long-term viability of the WCSB.

AltaGas' strategy is to:

- Maximize the profitability of the current field gathering and processing infrastructure:
 - Increase revenues by converting contracts to flowthrough operating costs and market-based fees;
 - Offer flexible contractual terms and equal access to all producers;
 - Enhance operational efficiencies through consolidation and plant upgrades and integration with other business segments;
 - Integrate operational support for the peaking power plants; and
 - Manage costs and improve reliability;
- Grow its field gathering and processing infrastructure:
 - Expand into areas of unconventional gas production such as CBM, shale gas and tight gas, where dedicated infrastructure is required to meet processing needs;
 - Expand into areas of high producer activity where there is increasing demand for gas gathering and processing infrastructure such as northwest Alberta and northeast British Columbia;
 - Invest in moveable assets that can be easily and quickly redeployed to new locations, improving operational flexibility and profitability and responding quickly to producer requirements;
 - Increase working interests to control operations, increase efficiency and reduce operating costs;
 - Acquire underutilized assets that offer upside through increased throughput in areas where production is expected to support the investment; and
 - Construct or acquire and connect complementary facilities to create large facility complexes to capture operating synergies.

AltaGas also enhances the value of its gathering and processing infrastructure by integrating its Field Gathering and Processing segment with AltaGas' other business segments. The resulting suite of integrated services such as natural gas transmission, NGL extraction and natural gas and NGL marketing enhances value for its customers and investors.

Field Gathering and Processing - Opportunities

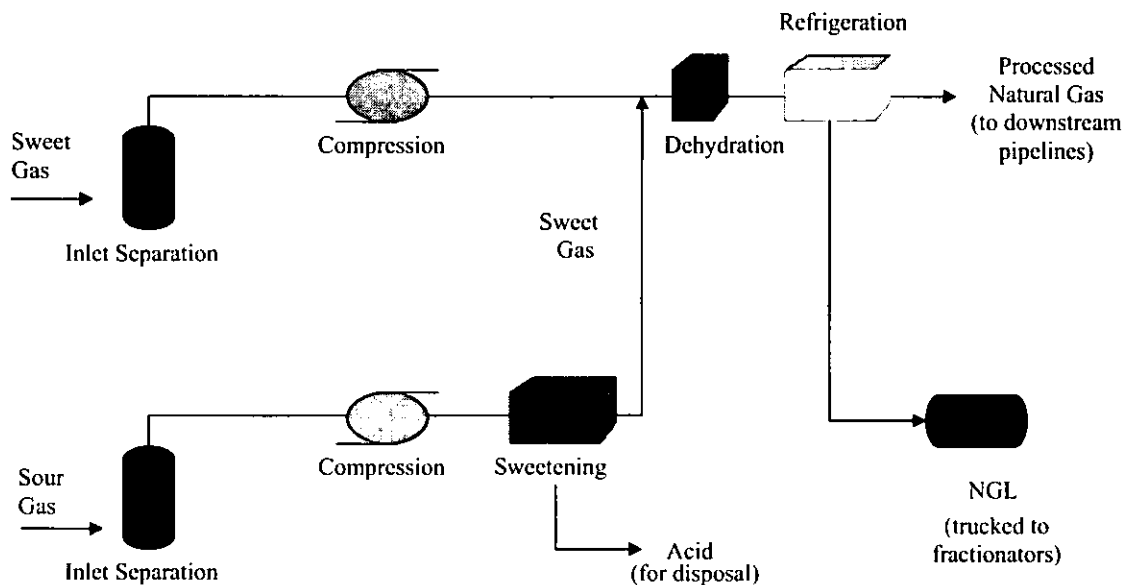
The Field Gathering and Processing segment has many opportunities to execute its strategy and to meet the existing and future gathering and processing needs of its customers. In addition to its network of approximately 6,500 km of gathering lines, substantial processing capacity, expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities, approximately 80 percent of its compression units are skid-mounted. This allows AltaGas to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers. At present, the majority of gathering and processing infrastructure in western Canada is owned by oil and natural gas producers with approximately 20 percent of the volumes in the WCSB processed by independent gas processors, including 3 percent processed by AltaGas. AltaGas believes that its strong operating skills and moveable assets create opportunities to work with customers to provide field gathering and processing services in a cost-effective and efficient manner.

New area development comes in large part from the drilling programs of AltaGas' existing and expanding customer base. Reserves analysis indicates that there are significant opportunities to increase natural gas production, including unconventional reserves within the WCSB, many in areas where gathering and processing infrastructure is limited thus providing opportunities for new infrastructure investment.

AltaGas may also see increased opportunities to acquire or build gathering and processing infrastructure from or on behalf of producers wishing to redeploy capital on exploration and production activities rather than on non-core activities such as processing.

Existing field gathering and processing areas usually have adjoining or overlapping gathering and processing systems. As AltaGas has grown, opportunities to expand by tying in new wells and building or purchasing adjoining facilities and systems have increased.

Field Gathering and Processing – Typical Field Gas Processing Plant



Raw natural gas produced at the wellhead is a mixture of methane and other hydrocarbon components and impurities, including water vapour, carbon dioxide and hydrogen sulphide. Raw gas with amounts of hydrogen sulphide in excess of downstream pipeline specifications is considered sour. All other gas is considered sweet. Sour gas goes through more extensive processing – known as sweetening – in order to remove the hydrogen sulphide and ensure that the gas meets pipeline specifications. All natural gas must be processed through a natural gas plant to remove impurities and the various hydrocarbon components before the natural gas is delivered via downstream pipelines for ultimate sale and consumption. The amount and complexity of processing required before the raw gas is of saleable quality is a function of the quantity of NGLs and impurities present in the raw gas stream.

The raw natural gas is first gathered from the wellhead through natural gas gathering systems, and then delivered to and processed through a natural gas processing plant. The design of a natural gas processing plant is determined by the composition of the raw gas that it is intended to process. Natural gas that contains minimal or no amounts of NGLs or other elements will bypass certain processes within a typical natural gas plant configuration.

Raw natural gas entering the natural gas plant is subject to inlet separation where free water and any free NGLs are separated from the natural gas stream. If the natural gas is sour, it is sweetened by the removal of hydrogen sulphide. The natural gas is then usually dehydrated to remove any remaining water. If significant NGLs are still present in the sweet gas they are removed to meet downstream pipeline specifications. NGLs generally have greater value if extracted in liquid form and additional NGL recovery beyond downstream pipeline specifications may be carried out in order to capture the value of the NGLs. This additional recovery process can be done at field gas plants or at large-scale extraction plants. See "Extraction". AltaGas has NGL extraction capability at 31 of its natural gas field processing facilities.

The remaining processed gas exiting the natural gas plant is delivered to the downstream transportation pipeline for eventual distribution to end-use markets. NGLs must be further processed (fractionated) into their individual components: propane, butane and pentanes-plus. The NGLs may be fractionated on site or trucked or pipelined to fractionation facilities.

Field Gathering and Processing - Facilities

AltaGas' Field Gathering and Processing segment generates revenue from fees for volumes of natural gas processed at a processing facility or gathered through a gathering system.

AltaGas strives for continued improvement, operational excellence, and maximum utilization of all facilities over which it has operational control and to consistently exceed WCSB average utilization rates. Volume additions at facilities, which come from new well tie-ins and from reactivations, recompletions and well optimizations performed by producers, are offset by natural production declines. The focus on skid-mounted facilities allows AltaGas to redeploy these assets in response to producer processing requirements, thereby increasing processing volumes, profitability and utilization.

Field Gathering and Processing Facility Capacity and Throughput (Excludes RET Complex)

	2007	2006
Capacity (gross Mmcfd) ⁽¹⁾⁽³⁾	1,023	1,021
Capacity growth year-over-year (%)	-	6
Throughput (gross Mmcfd) ⁽²⁾⁽³⁾	511	549
Throughput (gross annual Mmcfd) ⁽³⁾	527	555
Capacity utilization (%)	52	54

(1) As at December 31.

(2) Fourth quarter average.

(3) Gross numbers are before and are not adjusted to reflect AltaGas' working interest.

Natural gas demand resulted in an estimated 12,635 gas well completions and approximately 16.2 Bcf/d of marketable production in the WCSB during 2007, according to Ziff Energy Group. The Field Gathering and Processing segment connected 304 wells in 2007, compared to 384 wells tied-in during 2006. The softening of gas prices delayed producer activities in 2007 in most AltaGas areas.

Average facility utilization declined to 52 percent in 2007 from 54 percent in 2006. AltaGas experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity was impacted by lower profitability and uncertainty regarding the implications of the new Alberta royalty regime which was not announced until October 2007. In 2008 AltaGas expects producer activity to rebound since average operating costs have declined, natural gas prices remain above the lows of 2007 and the introduction of Alberta's new royalty framework should bring greater certainty to the industry. As a result, AltaGas expects demand for gathering and processing facilities to increase, thereby mitigating the impact of natural declines. AltaGas also expects its strategy of increasing the percentage of operating costs flowed through to producers, volumes from its new facilities and take-or-pay provisions to mitigate the impact of lower tie-ins and natural declines.

Field Gathering and Processing - Significant Operating Areas

AltaGas has historically focused on owning and operating smaller, moveable natural gas processing facilities in western Canada with processing capacity of under 50 Mmcfd, which it believes has distinguished it from most of its competitors. AltaGas' facilities are often physically linked, creating facility complexes that offer delivery options and revenue continuity in the event that one of the plants in a complex shuts down.

In 2007 AltaGas constructed the Acme facility specifically to process a new CBM development. In addition, AltaGas acquired the 5 Mmcfd Corbett Creek processing facility and gathering lines in an area of significant CBM production.

Effective July 31, 2007 AltaGas sold its one-third interest in the Ikhil Joint Venture to Utility Group as part of its divestiture plan for non-core production assets. The Ikhil Joint Venture delivered an average of approximately 1.5 Mmcfd of sweet dry gas into an 8 Mmcfd field processing facility. During the third quarter of 2007, the 5 Mmcfd Del Bonita facility was removed from service due to lack of success by area producers in finding significant reserves. The facility has been dismantled and equipment redeployed to other AltaGas operating areas.

As part of the acquisition of Taylor, effective January 10, 2008 AltaGas acquired an 88.2 percent interest in the three interconnected facilities of the RET Complex with gross capacity of 150 Mmcfd. AltaGas also became the operator of the RET Complex as a result of the acquisition.

With 77 processing plants in 30 operating areas including the RET Complex, AltaGas' Field Gathering and Processing segment is not dependent on any one facility or operating area.

The following table provides a summary of AltaGas' most significant field gathering and processing operating areas as at December 31, 2007, excluding the RET Complex:

Operating Area	Ownership (percent)	Facility Type	Facility Count	Gross Capacity (Mmcf/d) ⁽¹⁾	Gross Throughput (Mmcf/d) ⁽¹⁾⁽²⁾	Number of Compressors (includes boosters)	Operated or Non-operated
Western Canada							
North							
Ante Creek	100.0	sweet	1	36	25.8	2	Operated
Barrhead	68.0	sweet/sour	6	72	17.7	15	Operated
Blair Creek	100.0	sweet	1	24	4.7	2	Operated
Clear Hills	100.0	sour	1	10	7.6	2	Operated
Clear Prairie	100.0	sweet	1	15	2.7	1	Operated
CMB ⁽³⁾	75.0	sweet/sour	3	16	7.3	7	Operated
Cold Lake	86.6	sweet	8	67	35.3	31	Operated
Pouce Coupe	76.75	sweet	1	43	5.8	2	Operated
Prairie River	100.0	sweet	1	20	7.7	8	Operated
Rainbow Lake	100.0	sour	1	40	20.7	2	Operated
Thornbury	100.0	sweet	7	32	11.0	14	Operated
Wabasca	100.0	sweet/sour	4	90	41.2	17	Operated
Windfall	100.0	sweet	2	44	20.5	4	Operated
Subtotal - North			37	509	208.0	107	
South							
Acme	100.0	sweet	1	10	1.8	2	Operated
Alder Flats	100.0	sweet	1	40	13.7	3	Operated
Bantry	100.0	sour	1	25	11.5	8	Operated
Birch Wavy South	89.5	sweet	5	28	25.7	12	Operated
Birch Wavy North	81.0	sweet	7	78	53.5	28	Operated
Bonnie Glen	100.0	sweet	2	41	58.9 ⁽⁴⁾	11	Operated
Central Border	100.0	sweet/sour	8	90	45.0	24	Operated
Kirkpatrick	100.0	sweet	1	14	6.9	5	Operated
Princess	100.0	sour	1	20	11.3	1	Operated
South Foothills	66.0	sweet/sour	3	78	39.5	9	Operated/ Non-operated
Sylvan Lake	100.0	sweet	1	30	19.4	9	Operated
Other South	100.0	sweet/sour	5	55	14.4	12	Operated/ Non-operated
Subtotal - South			36	509	301.6	124	
Montana, USA							
Coutts	100.0	sweet	1	5	1.0	-	Operated
Total			74	1,023	510.6	231	

(1) Gross numbers and not adjusted to reflect AltaGas' working interest.

(2) Represents fourth quarter average.

(3) Craigend, Elinor Lake (formerly McGuffin Lake) and Beaver Lake.

(4) Includes volumes gathered, but not processed, at AltaGas' plant.

Field Gathering and Processing - Customers

In 2007 AltaGas conducted business with more than 250 customers in its operating areas, with no customer representing more than 6 percent of Field Gathering and Processing net revenue during 2007. The Field Gathering and Processing segment's top 10 customers represented 13 percent of consolidated net revenue for 2007.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. There are approximately 1,400 active gathering and processing contracts. These contracts, in general:

- Establish fees for the gathering and processing services offered by AltaGas;
- Define the producers' access rights to gathering and processing services;
- Establish minimum throughput commitments with producers and use appropriate fee structures to recover invested capital early in the life of the contract where capital investment is required by AltaGas;
- Define the terms and conditions under which future production is processed at an AltaGas facility; and
- Assist in mitigating volume risk.

The amount of capital that AltaGas commits to acquiring or developing gathering and processing facilities is linked to AltaGas' assessment of the production available to be processed at the facility, reserves in the area, the extent of the reserve dedication and the processing fees to be paid by producers for its services. When a facility is acquired, AltaGas conducts an independent review of the natural gas reserves and production in the area surrounding each facility using, among other sources, ERCB production data and reserve estimates and producers' reserve reports for the area. AltaGas also conducts a review of the physical plant and equipment and the operating and maintenance costs for each facility.

Fee Structure

In determining appropriate contractual provisions, including a reasonable payback period on its invested capital, AltaGas seeks to align its interests with the financial and business objectives of its producer customers. The vast majority of AltaGas' gathering and processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput. Volumetric fee structures may include a provision for recovery of actual operating costs, which further mitigates the financial risk related to volume variability. Operating costs recovery in 2007 remained constant at 39 percent compared with 2006. In addition, approximately 79 percent of contracts in place at December 31, 2007 were subject to annual price escalation related to changes in the Alberta Consumer Price Index. This toll-for-service structure (as opposed to the commodity spread-based price structures predominantly used by midstream companies in the U.S.) avoids exposure to commodity price risk as revenue is a function of volumes processed. AltaGas' investment is generally protected by the life of reserves behind the facility, since producing wells typically remain connected to a gathering and processing system for their entire productive lives.

AltaGas may underpin capital commitments through the use of one or more of the following contractual provisions:

Take-or-Pay: Take-or-pay arrangements are designed to ensure AltaGas recovers its invested capital in a relatively short period of time. This is achieved by producers providing minimum volume or capital recovery commitments to AltaGas. With minimum volume commitments the producer must process a specified volume at a rate per Mcf over a specified period of time or pay any revenue shortfall. The sum of the processing revenue provides AltaGas with a return on and of capital within a specified period. Risk is limited to counterparty creditworthiness. In recent years, AltaGas' strategy has shifted to minimum monthly volume commitments to decrease credit risk and lead to predictable cash flow.

Capital and Operating Cost Recovery: The producer pays two distinct fees to AltaGas, one to provide a return of and on capital and the other to cover AltaGas' operating costs. Return of and on capital is made more certain by reducing the risk of unexpected operating costs. Risk is largely limited to the timing of production.

Area of Mutual Interest: When AltaGas acquires a facility the vendor is typically the largest producer using that facility. As a result, AltaGas is usually entitled to gather and process the majority of the natural gas production associated with the facilities it acquires due to its reserve dedication contracts, thus reducing the possibility of competitive plants being built in the same area. Risk is largely limited to the timing of production. The contract terms also ensure any future production brought on stream in a specified area must flow to an AltaGas facility. Future natural gas throughput is generally secured by contractually committing the vendor of the facility to dedicate any future production from specified reserves or future areas of development surrounding the facility.

Geographic Franchise with Economic Out: Contractual provisions allow AltaGas to terminate or renegotiate a contract if it is not economical to continue processing. Risk is largely limited to the timing of production and operating cost efficiencies.

Length of Term

Where natural gas reserves have been dedicated under contract, the contract normally extends beyond one year and up to the life of the reserves, depending on the amount of capital AltaGas has invested in the facility. Where reserves have not been dedicated under contract or AltaGas has not made a significant capital investment, the contracts are normally subject to termination by either party upon one to three months notice. As mentioned previously, producing wells typically remain connected to a gathering and processing system for their entire productive lives.

Type of Service

In general, producers have access to either firm service or interruptible service. Firm service offers producers priority to have their natural gas processed at the applicable AltaGas facility subject to industry standard maintenance and force majeure. Interruptible service is available only if the applicable AltaGas facility has capacity available after all firm service commitments with respect to such facility have been satisfied. Firm service is normally provided to a producer when the producer's natural gas reserves have been dedicated to an AltaGas facility.

Field Gathering and Processing - Operating and Maintenance Expenses

Operating and maintenance expenses for gathering and processing facilities generally include: (i) labour costs for operators; (ii) materials consumed in processing or maintenance, including chemicals and lubricants; (iii) land lease costs; (iv) property taxes; (v) fuel and power costs; and (vi) other overhead costs. For the plants operated by AltaGas, the most significant expenses are labour, utilities, property taxes and repairs and maintenance. Repairs and maintenance are scheduled, where possible, to minimize down time and coordinate with producers' well maintenance activities. One of AltaGas' strategies is to increase the number of contracts with flowthrough operating costs provisions.

Field Gathering and Processing - Competition

Independent midstream companies currently provide a small portion of the midstream field processing function in Canada. AltaGas estimates that on a net capacity basis, approximately 20 percent of the total estimated field processing capacity in western Canada is owned by independent midstream entities. AltaGas competes with other midstream entities operating in the WCSB, including Keyera Facilities Income Fund, Spectra Energy Income Fund (formerly Duke Energy Income Fund), SemCanada, L.P., Provident and ATCO Midstream Ltd. In 2007 AltaGas processed an average of 527 Mmcfd, which was approximately 3 percent of volumes produced in the WCSB. The majority of processing capacity generally continues to be provided by the upstream natural gas exploration and production companies.

The field gathering and processing marketplace continues to evolve and the competitive environment also continues to change. AltaGas believes that its field gathering and processing strategies and competitive advantages will continue to allow it to effectively compete in the midstream marketplace. AltaGas also believes that its operational skills and market penetration make it a preferred business partner for many exploration and production companies.

EXTRACTION AND TRANSMISSION

AltaGas' Extraction and Transmission segment contributed net revenue of \$67.4 million for the year ended December 31, 2007, representing approximately 21 percent of the Trust's total net revenue before intersegment eliminations. Total growth capital spent on extraction and transmission facilities during 2007 was \$3.3 million.

Extraction and Transmission – Business Strategy

The Extraction and Transmission segment provides safe and reliable processing and transportation services to its customers. The strategic focus is on optimizing current infrastructure and increasing throughput and market share to improve profitability through long-term fixed-fee or cost-of-service contracts.

The Extraction and Transmission segment's business strategy is to:

- Maximize the profitability of the extraction and transmission infrastructure:
 - Increase throughput and utilization of existing extraction and transmission infrastructure;
 - Recontract for services to increase returns;
 - Execute commercial arrangements that have long-term fixed-fee or cost-of-service components;
 - Use frac spread hedges to lock-in margins and reduce exposure to frac spread volatility;
 - Operate plants to mitigate downside risk when frac spreads are low;
 - Leverage existing assets and services to capture accretive growth; and
 - Offer marketing, transportation management and processing services in cooperation with the Energy Services and Field Gathering and Processing segments;

- Grow its extraction and transmission infrastructure:
 - Acquire and develop new facilities; and
 - Increase working interest ownership of partially owned plants.

The main business driver in the extraction business is the volume of ethane and NGLs produced, which is directly correlated to the volume of natural gas processed, natural gas composition, recovery efficiency of the extraction plant, plant on-line time, contractual arrangements and commodity price.

The main value drivers in the transmission business are the fees earned, which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market.

Extraction and Transmission - Opportunities

Extraction growth opportunities may arise from plant modifications to increase product recoveries at facilities in which AltaGas already has ownership, increasing interests in existing extraction plants, through construction of new facilities and by increased throughput due to additional extraction agreements. Extraction plant opportunities typically reflect a long-term, cost-of-service ethane processing arrangement contracted with Alberta ethylene producers, long-term NGL fixed processing fee arrangements and a small percentage of short-term sales of NGLs based on an Edmonton or U.S. index.

Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is limited or non-existent. In capturing opportunities, AltaGas focuses on long-term, cost-of-service type contractual arrangements. Increased activity in heavy oil in the Cold Lake area is expected to provide AltaGas with additional opportunities to expand its Cold Lake system similar to the expansion completed in 2007. Drilling activity in areas served by AltaGas' other transmission assets is also expected to provide opportunities to expand infrastructure and increase utilization of the assets.

Extraction - Business Description

AltaGas owns extraction plant processing capacity through its interest in two extraction plants at Empress, Alberta, an extraction plant at Joffre, Alberta and another in Edmonton, Alberta. Also included in the extraction business is AltaGas' Bantry field fractionation facility. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was 554 Mmcfd at December 31, 2007. With the Taylor acquisition effective January 10, 2008, AltaGas added the wholly owned Harmattan Complex in Alberta, a 56.7 percent interest in NGL extraction and a 100 percent interest in NGL fractionation and terminalling at the Younger Extraction Plant in British Columbia and increased its ownership of the Joffre Extraction Plant in Alberta to 100 percent. The Harmattan Complex has natural gas licensed inlet capacity of 490 Mmcfd, a deep cut NGL extraction unit and NGL fractionation net capacity of 25,000 Bbls/d and NGL terminal facilities. The Younger Extraction Plant has net processing capacity of 425 Mmcfd and NGL fractionation and terminal ownership with net capacity of 25,000 Bbls/d. The increased ownership of the Joffre plant added net capacity of 125 Mmcfd and terminalling with net capacity of 5,200 Bbls/d. AltaGas operates EEEP, the Bantry field fractionation facility, and, from January 10, 2008, the Joffre Extraction Plant, the Harmattan Complex and the Younger Extraction Plant.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities and their value as constituents of the natural gas stream. This difference is commonly known as the frac spread. If the components are not extracted, they are sold as natural gas for their heating value at the prevailing natural gas price. As ethane and NGLs, the components are sold at higher prices that reflect the premium value of each of the individual commodities. In most cases the NGLs recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGLs to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGLs are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. NGLs, predominantly ethane, are feedstock for ethylene production.

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through gas extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy contained in the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby

keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements.

Extraction - Plant Fee Structures

Extraction facility owners obtain the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through gas extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy contained in the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively replaces the extracted energy, thereby keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas.

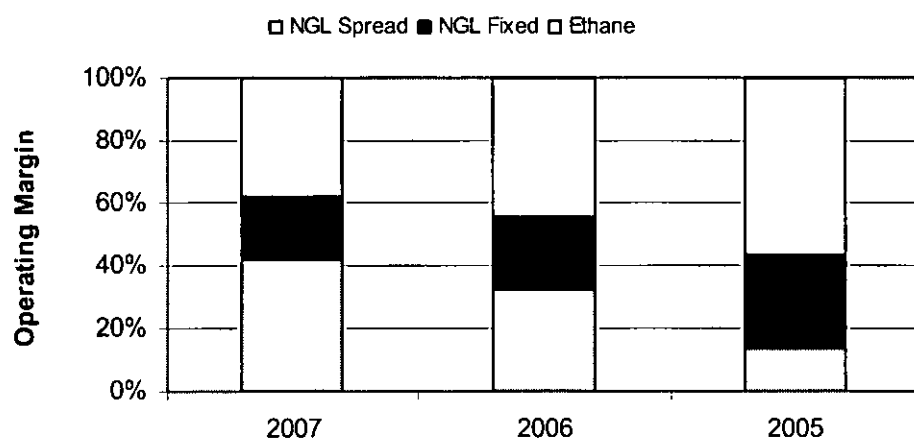
AltaGas' share of all ethane production is sold through long-term, cost-of-service or fixed-fee arrangements that bear no commodity price risk (ethane cost-of-service contracts). The sales price received under these contracts provides for a return on and of capital and the recovery of certain operating costs, including shrinkage gas attributable to that production. AltaGas' share of ethane production is sold at the outlet of the plants, with the product purchaser responsible for all downstream transportation and handling. AltaGas' ethane sales provide a stable, predictable cash flow base.

AltaGas' NGL production is sold under a variety of arrangements. Approximately 70 percent of AltaGas' NGL production is sold under long-term, fixed-fee arrangements (NGL fixed-fee contracts). These volumes do not bear any commodity price risk. The revenue from this portion of NGL sales provides a stable, predictable cash flow base.

On the portion of the extraction production that is not sold under ethane cost-of-service contracts or NGL fixed-fee contracts, performance is subject to the price spread between NGLs extracted and the natural gas purchased to make up the heating value of the NGLs extracted (frac spread).

Approximately 26 percent of AltaGas' NGL production (8.7 percent of total extraction production) is sold under short-term contracts subject to frac spread (NGL spread contracts). If commodity prices or operating costs make NGL extraction uneconomical, the NGLs may be reinjected or the facilities may be turned down or shut-in. When this occurs, the operational flexibility of the commercial contracts translates into a minimal effect on margins.

The following diagram shows the operating margin based on type of extraction contract. In 2007 AltaGas benefited from historically high frac spreads.



Extraction – Plant Production

Extraction production is a function of natural gas volume processed, natural gas composition, recovery efficiency of the extraction plant and plant on-line time. The following table represents a summary of AltaGas' capacity and the production associated with extraction and fractionation plants in which AltaGas holds an interest:

Extraction or Fractionation Plant	Interest (%) ⁽¹⁾	AltaGas' Inlet Processing Capacity (Mmcfd) ⁽¹⁾	2007 Liquids Production (Bbls/d) ⁽²⁾		2006 Liquids Production (Bbls/d) ⁽²⁾		Operated or Non-Operated
Edmonton (EERP)	48.667	190	NGLs	2,482	NGLs	2,290	Operated
			Ethane	7,470	Ethane	7,815	
Empress ATCO (EGLJV)	7.2	79	NGLs	913	NGLs	678	Non-Operated
			Ethane	958	Ethane	703	
Empress Provident (PEEP)	11.25	135	NGLs	1,648	NGLs	1,375	Non-Operated
			Ethane	2,931	Ethane	2,456	
Joffre (JEEP) ⁽³⁾	50.0	125	NGLs	958	NGLs	882	Non-Operated
			Ethane	2,900	Ethane	2,861	
Bantry	100.0	25	NGLs	214	NGLs	232	Operated
Total⁽⁴⁾		554	NGLs	6,215	NGLs	5,457	
			Ethane	14,259	Ethane	13,835	

(1) At December 31, 2007.

(2) Average volumes for the fourth quarter.

(3) On January 10, 2008 AltaGas completed the acquisition of Taylor, which owned 50 percent of JEEP and was the operator as at December 31, 2007. With the completion of the acquisition, AltaGas owns 100 percent of JEEP and is the operator.

(4) Excludes field NGLs.

AltaGas' extraction and field fractionation plant annual average production for the last two years is as follows:

Extraction and Fractionation Plant Production ⁽¹⁾	2007	2006
NGLs (Bbls/d)	6,752	6,564
Ethane (Bbls/d)	13,356	13,132
Total	20,108	19,696

(1) Average Bbls/d to AltaGas for years ended December 31.

Extraction - Empress ATCO Extraction Plant

At December 31, 2007 AltaGas' ownership interest in the Empress ATCO extraction plant located in southeast Alberta on the Alberta-Saskatchewan border was 7.2 percent. The remaining 92.8 percent interest in the facility is held by nine other owners with varying interests. AltaGas' ownership corresponds to a 79 Mmcfd share of the plant's 1,100 Mmcfd of natural gas inlet capacity. Current firm gas supply under contract is 79 Mmcfd, of which 24 Mmcfd is under contract until December 2009 and the remainder is made up of yearly and monthly supply arrangements. At the Empress ATCO extraction plant, AltaGas also processes any interruptible gas volumes that are made available to the plant by the Energy Services segment and any gas volumes diverted from the shutdown of its other Empress facility. As there are five other extraction plants in the Empress area, there is considerable competition amongst the owners of the plants for producers' extraction rights. The Empress ATCO plant consists of four processing trains which provide the flexibility to easily manage production to reduce operating costs and operational risk, minimizing any downside risk associated with fluctuating production volumes.

AltaGas' ethane production is sold under a long-term, cost-plus sales arrangement. AltaGas' share of NGL production at the Empress ATCO plant is sold under one-year evergreen marketing arrangements at the monthly market price for NGLs. In addition to this marketing arrangement, approximately 36 percent of AltaGas' share of NGL production generates revenue subject to a long-term profit and loss arrangement that includes a processing fee and revenue that varies with product pricing.

Extraction - Empress Provident Extraction Plant

Effective April 1, 1998 AltaGas acquired a 10 percent interest in the Empress Provident extraction plant, which began operations in September 1996 and is located 2 km southeast of the Empress ATCO extraction plant. The plant is licensed

to process 1,200 Mmcf/d of natural gas, of which 120 Mmcf/d was AltaGas' share. In October 2003 modifications were completed to increase the ethane recovery efficiency. AltaGas' share of the modification costs was \$5.5 million and the project more than doubled its ethane production to approximately 2,400 Bbls/d. Effective December 15, 2006 AltaGas increased its interest in the plant to 11.25 percent and its share of processing capacity to 135 Mmcf/d.

AltaGas has managed its gas supply risk at this plant by securing sufficient natural gas throughput on a long-term basis to ensure that its share of 135 Mmcf/d is fully utilized at all times.

AltaGas' share of ethane production is sold under a long-term, cost-of-service type contract that provides for the recovery of certain operating costs. Approximately 74 percent of AltaGas' share of NGL production from this plant generates fixed-fee revenue plus reimbursement of associated operating costs under a long-term processing arrangement. The remainder is sold under a one-year evergreen marketing arrangement at the monthly market price for NGLs.

Extraction - Joffre Extraction Plant

AltaGas and Taylor each owned 50 percent of the ethane extraction plant at Joffre, Alberta at December 31, 2007 and their respective share of processing capacity was 125 Mmcf/d of natural gas. With the acquisition of Taylor effective January 10, 2008, AltaGas now owns 100 percent of the Joffre Extraction Plant which has processing capacity of 250 Mmcf/d of natural gas and is capable of producing up to 10,400 Bbls/d of ethane and NGLs. The Joffre plant, which was constructed in 2002 at a net cost to AltaGas of \$24.8 million, started operations in December 2002. Taylor was operator of the facility at December 31, 2007. AltaGas now operates the facility.

The Joffre plant is adjacent to NOVA Chemicals Corporation's Joffre petrochemical complex and recovers ethane and NGLs from the fuel gas used at the complex. All ethane production from the Joffre plant is sold under a cost-of-service type contract with NOVA Chemicals Corporation that expires in 2031. Under this ethane sales agreement, a small portion of the operating cost risk is borne by AltaGas, based on the ratio of NGLs to total plant production. AltaGas sells its NGL production under a one-year evergreen marketing agreement based on the monthly average market price for NGLs.

The Joffre plant is physically configured such that NGL production can easily be matched to market demand. This ability to step in and out of the NGL market depending on NGL pricing allows AltaGas to fully participate in the market when NGL prices are strong, while minimizing exposure during times of unfavourable pricing.

Extraction - Edmonton Ethane Extraction Plant

In late August 2004 AltaGas acquired a 48 ²/₃ percent interest in EEEP for \$48.2 million, including an environmental liability of \$5.0 million, for a net cash outlay of \$43.2 million. The remaining interest in the plant is held by ATCO Midstream Ltd. AltaGas operates the plant. The plant has a licensed gross inlet capacity of 390 Mmcf/d of natural gas and gross production capacity of specification ethane of 23,000 Bbls/d and NGLs of 7,500 Bbls/d. A long-term gas supply contract provides a secure feedstock supply to EEEP. AltaGas' share of the plant products is sold under long-term contracts through cost-of-service or cost-plus sales arrangements.

In January 2007 a \$4.6 million project (AltaGas share \$2.2-million) to increase processing capability and ethane recovery at EEEP was completed. The project increased AltaGas' processing capability by 15 Mmcf/d, with no change to licensed capacity. This project increased ethane production at the plant by almost 10 percent on an annualized basis, adding 700 Bbls/d of ethane for AltaGas.

EEEEP is directly connected to the Alberta Ethane Gathering System, and to BP Canada Energy Resources' Co-Ed NGL pipeline, providing safe and reliable outlets for the plant products. The processed gas from the facility supplies end-use markets in the city of Edmonton, Alberta.

Extraction - Bantry Field Fractionation Facility

AltaGas purchased the Bantry natural gas processing plant in May 2000 and expanded it in 2001. See "Field Gathering and Processing - Facilities". The plant is equipped with fractionation facilities capable of producing up to 400 Bbls/d of specification propane, butane and pentanes-plus for sale to local markets at market prices. Fractionation services at Bantry are provided at a rate per m³ of product processed.

Extraction - Younger Extraction Plant

With the acquisition of Taylor effective January 10, 2008, AltaGas acquired a 56.7 percent interest in Younger Extraction Plant. The Younger Extraction Plant processes natural gas transported on the Spectra transmission system and the CNRL Stoddart transmission system to recover NGLs. All of AltaGas' NGL production from the Younger Extraction Plant is sold to Provident under a long-term NGL purchase agreement which consists of a return on capital, recovery of

operating costs, shrinkage make-up and a profit-share component. Provident sources all gas supply to the Younger Extraction Plant as part of the NGL purchase agreement.

The Younger Extraction Plant has 750 Mmcf/d of natural gas processing capacity. AltaGas' share of the natural gas processing capacity is 425 Mmcf/d and Provident's share is 325 Mmcf/d. AltaGas owns 100 percent of the facilities related to fractionation, storage, loading, treating or terminalling of NGLs. AltaGas operates the Younger Extraction Plant.

Extraction - Harmattan Complex

With the acquisition of Taylor effective January 10, 2008, AltaGas acquired a 100 percent interest in the Harmattan Complex which is located about 100 km north of Calgary, Alberta. Harmattan has natural gas processing capacity of 490 Mmcf/d consisting of sour gas treating, NGL extraction and 25,000 Bbls/d of NGL fractionation and terminalling. Harmattan also has a 450 Bbls/d capacity frac oil processing facility, a 200 tonnes/d capacity industrial grade CO₂ facility and a 6,000 Bbls/d capacity NGL truck offload facility.

The Harmattan Complex generates fee-for-service revenues from raw natural gas processing, NGL extraction, fractionation and terminalling, and custom NGL processing. Fee-for-service means that fees are charged to the customer for the service provided on a per unit volume basis.

At the Harmattan Complex, natural gas processing services are currently provided to approximately 60 producers under contracts with a variety of commercial arrangements and terms. At present, approximately 55 percent of the natural gas volume processed at the Harmattan Complex is done under the terms of the Rep Agreements. The Rep Agreements have life-of-reserves dedicated to the Harmattan Complex. In addition to the natural gas processed under the Rep Agreements, a further 25 percent of the natural gas currently being processed at the Harmattan Complex is committed for over eight years with annual minimum volume obligations. The balance of the raw natural gas processed at the Harmattan Complex is processed under contracts with terms varying from one month to ten years. The majority of the contracts, including the Rep Agreements, provide for fee escalation based on the CPI.

The Harmattan Complex extracts NGLs from the raw natural gas delivered for processing, fractionates the recovered NGLs into specification ethane, propane, butane and condensate, and provides storage and terminalling services for each product. The terminalling options for each product are:

Ethane – The Harmattan Complex is connected to the Alberta Ethane Gathering System by an interconnecting pipeline that is owned by AltaGas. All ethane produced at the Harmattan Complex is delivered to the Alberta Ethane Gathering System.

Propane and butane – Producers may have their propane and butane loaded onto either rail or truck. The rail loading facilities, which are located at Didsbury, Alberta, are connected by pipeline to the main complex.

Condensate – Producers may have their condensate delivered to either the Cremona pipeline or loaded onto trucks at the Harmattan Complex.

The Harmattan Complex also receives NGLs at its truck offloading facilities for fractionation and terminalling. Fees for handling these NGLs are charged on a per unit basis. Once fractionated into specification propane, butane and condensate, the products have the terminalling options described above.

Under the terms of many of the raw natural gas processing agreements, a component of the compensation received by AltaGas for providing services to the producers is derived by AltaGas having the right to purchase a portion of the producers' ethane, propane, butane and condensate for a price equal to the value of the equivalent natural gas. This commercial arrangement is known as product-in-kind.

The profitability of product-in-kind arrangements is a function of the difference between the value of specification ethane, propane, butane and condensate and the value of NGLs if they remain in the natural gas. The ethane acquired by AltaGas under the product-in-kind arrangements is sold under a long-term contract for a price that includes full recovery of the cost of acquiring the ethane from the producers plus a premium. The propane, butane and condensate volumes acquired by AltaGas are small and are sold into the Alberta market at prevailing prices.

AltaGas generates marketing revenues from the sale of specialized commodities that are produced at the Harmattan Complex. The facilities used to produce these products are for the exclusive use of AltaGas.

Frac oil – The Harmattan Complex includes facilities that refine condensate into a premium hydrocarbon-based product known as frac oil. AltaGas acquires the condensate feedstock from Harmattan-area producers or by purchasing condensate from other natural gas processing facilities in other areas. The frac oil produced at the

Harmattan Complex has been branded "Harmattan Premium" and is used in the servicing and maintenance of oil and natural gas wells. The Harmattan Complex has storage and terminalling facilities necessary to sell frac oil to a truck based market. Currently, Harmattan Premium is sold to a single customer under a one-year evergreen contract.

CO₂ – CO₂ is produced as a result of processing raw natural gas to meet sales natural gas specifications. The Harmattan Complex has facilities that recover this CO₂ to produce industrial grade liquid CO₂. The recovery of this reduces the Harmattan Complex's CO₂ emissions. The liquid CO₂ is sold at a truck rack to a single customer under a take-or-pay contract with approximately seven years remaining.

Extraction - Competition

Currently there are six extraction plants in the Empress area, resulting in significant competition for natural gas supply. AltaGas has long-term natural gas supply contracts and access to gas supply through the Energy Services Segment. The strategic locations and contractual arrangements in place at EEEP and the Joffre Extraction Plant also help AltaGas to compete.

The Younger Extraction Plant processes natural gas produced in the Fort St. John basin located in northeast British Columbia. Provident manages the natural gas supply from this capture area. The Alliance pipeline competes for natural gas supply.

Transmission – Business Description

AltaGas owned five natural gas transmission systems with transportation capacity of approximately 554 Mmc/d and one condensate pipeline with 11,600 Bbls/d of capacity at December 31, 2007. With the acquisition of Taylor effective January 10, 2008 the transmission business now includes the Ethylene Delivery System and the Joffre Feedstock Pipeline. The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan area of Alberta. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. The JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The largest contributor to Transmission business is the Suffield natural gas transmission system located in southeastern Alberta which accounted for 72 percent of transmission net revenue in 2007. The Suffield system consists of two natural gas pipelines at Suffield located in southeastern Alberta which transport natural gas produced in and around the Suffield military block to the TransCanada Pipelines mainline at Burstall, Saskatchewan. The Suffield system is regulated by the National Energy Board and rates on the system are based on a market-based tolling methodology. The two pipelines have 400 Mmc/d of combined transmission capacity. The south Suffield pipeline is a 147-km pipeline of six to 16-inch diameter pipe and the north Suffield pipeline is 96 km of 16-inch diameter pipe.

The majority of the Suffield system's 400 Mmc/d capacity is currently contracted by EnCana Oil and Gas Partnership through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter. Volume commitments are expected to increase annually from approximately 370,000 GJ/d in 2007 to approximately 406,000 GJ/d in 2010 and decline thereafter. On the Suffield system, EnCana pays AltaGas based on a daily contract quantity (DCQ). To the extent that annual volumes shipped are less than the annualized daily contract quantity (shortfall volumes), AltaGas does not refund the shipper for payments made under the DCQ but posts the shortfall quantity to a shortfall account as a credit (revenue deferral) until such time as the shipper reduces the shortfall by delivering excess quantities or until the shortfall amounts expires.

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis. The Porcupine Hills pipeline in southeast Alberta is a single-shipper condensate pipeline. The Summerdale and Battle Lake pipelines transport natural gas in central Alberta.

The Porcupine Hills condensate pipeline delivers condensate from the Shell Waterton plant to the Town of Turner Valley for Shell Canada. The Porcupine contract, which expires on June 30, 2008, is expected to be extended on similar terms.

The EDS transportation agreement has an initial term of 12 years to 2016 with provisions for extensions thereafter. The payments made to AltaGas by NOVA Chemicals for transportation services are the sum of a fixed, transport-or-pay fee plus the full recovery of actual costs incurred in operating EDS. The fixed-fee is subject to an interest rate adjustment in

2009, and every three years thereafter, based on then-current interest rates. The EDS transportation agreement also contains provisions that define the incremental fees that will be charged to NOVA Chemicals in the event that additional capital is invested by AltaGas in the system.

The termination of the EDS transportation agreement at the end of the initial 12-year term requires five years' notice by NOVA Chemicals. After the initial term, the notice period to terminate is three years. NOVA Chemicals has the option to purchase the pipeline after the initial term on three years' notice at a price based on a 30-year straight-line depreciation, subject to a floor price. NOVA Chemicals cannot selectively renew only the EDS transportation agreements; the termination of the EDS transportation agreement requires the termination of the JFP transportation agreement.

The terms of the JFP transportation agreement are essentially identical to the terms in the EDS agreement. NOVA Chemicals cannot selectively renew only the JFP transportation agreement; the termination of the JFP transportation agreement requires the termination of the EDS transportation agreement.

The following table provides a summary of the gross capacity of AltaGas' transmission pipelines at December 31, 2007 and average throughput volumes for the fourth quarter, excluding the EDS and the JFP:

Transmission Pipeline	Product	Area	Ownership (percent)	Operating Capacity	Throughput ⁽¹⁾	Length (km)	Operated/ Non-operated ⁽²⁾
Battle Lake	natural gas	Central Alberta	100.0	15 Mmcf/d	1 Mmcf/d	16	Operated
Cold Lake	natural gas	East central Alberta	99.2	80 Mmcf/d	40 Mmcf/d	253	Operated
Kahntah	natural gas	Northeast B.C.	100.0	35 Mmcf/d	2 Mmcf/d	55	Operated
Suffield	natural gas	Southeast Alberta	100.0	400 Mmcf/d	348 Mmcf/d	243	Operated
Summerdale	natural gas	Central Alberta	100.0	24 Mmcf/d	12 Mmcf/d	18	Operated
Porcupine Hills	condensate	Southwest Alberta	100.0	11,600 Bbls/d	2,836 Bbls/d	164	Operated

(1) Represents fourth quarter average.

(2) AltaGas operates the Cold Lake pipeline and has subcontracted out the operator function at its five other pipelines.

POWER GENERATION

AltaGas' Power Generation segment contributed net revenue of \$104.2 million for the year ended December 31, 2007, representing approximately 32 percent of the Trust's total net revenue before intersegment eliminations. In 2007 AltaGas invested \$21.5 million in growth capital in the Power Generation segment.

AltaGas has 353 MW of power generation capacity through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired peaking capacity. AltaGas' 378 MW of installed power capacity as at December 31, 2007 served approximately 5 percent of Alberta's power demand. In 2007 AltaGas also purchased 14.4 MW of gas-fired peaking capacity which is currently being installed. AltaGas also has a 25 percent interest in a 7-MW run-of-river hydroelectric generation facility in British Columbia as a result of the acquisition of Taylor. The Power Generation segment is primarily engaged in the sale of electricity and ancillary services to the Alberta wholesale market.

Power Generation - Business Strategy

AltaGas' Power Generation strategy is to:

- Maximize the profitability of the existing power assets:
 - Evaluate, modify and refine the power hedge strategies as appropriate to increase earnings stability and growth from the Sundance PPAs;
 - Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy and ancillary services
 - Identify and execute opportunities to create value from the regulation of greenhouse gas emissions; and
 - Capitalize on internal synergies by increasing integration efforts with other operating segments;
- Grow its power infrastructure:

- Acquire and develop power infrastructure supported by strong power demand and supply fundamentals;
- Acquire and develop power generation projects supported by long-term power sales arrangements;
- Diversify power generation portfolio by geography and fuel source;
- Develop operating capability in other fuel sources;
- Capitalize on increasing demand for clean power by investing in renewable and clean power project development across Canada and the northern US; and
- Invest in power opportunities such as additional PPAs in Alberta and other jurisdictions.

Power Generation - Opportunities

The supply-demand fundamentals supporting the Power Generation segment remain favourable in North America. AltaGas expects this will continue to support strong power prices, especially in Alberta where the Trust is most exposed to power prices. This could increase the profitability of AltaGas' power generation assets allowing AltaGas to earn higher revenues from the sale of power and ancillary services. The expectation of continued strong power prices is supported by the tightening of the electricity reserve margin in Alberta, as transmission constraints are delaying the addition of new generation facilities. In December 2007, the AESO published a report titled "Future Demand and Energy Outlook, 2007-2027" which showed provincial demand growing at an average rate of 3.2 percent over the next five years. Given the demand and supply forecasts, AltaGas expects reserve margins to remain at less than 10 percent until 2011 at which time it is expected to increase to about 15 percent. In early 2008 the forward curve for power prices indicates that they are expected to remain relatively strong in the low to mid-\$70/MWh 2012. As at December 31, 2007, 93 percent of AltaGas' generation capacity was low-cost base-load coal-fired generation, resulting in strong future earnings in this market environment.

Power generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The planned decommissioning of thermal plants in Ontario, and, beginning in 2010, in Alberta, may present additional growth opportunities through the development and ownership of new capacity. In 2006 AltaGas forged relationships with power generation developers to pursue its strategy to grow its renewable energy portfolio. In 2007 AltaGas acquired 100 percent of BMWLP, which owns the Bear Mountain Wind Park under construction near Dawson Creek, British Columbia.

The Power Generation segment is poised for growth with the Bear Mountain Wind Park under construction and expected to be in service in November 2009. At present AltaGas owns 100 percent of the Bear Mountain Wind Park and intends to include one or more third-party investors in the project, which will reduce ownership in the wind park to approximately 45 percent. AltaGas also has several run-of-river hydroelectric projects, including two 10-MW plants with 40-year energy purchase arrangements with BC Hydro which are currently in the permitting and licensing phase and expected to be in service in 2010. In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric power generation in British Columbia. GreenWing has also developed a portfolio of power projects in Canada and the United States that AltaGas believes will fuel further growth in its power infrastructure.

Power Purchase Arrangements

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output.

ASTC Power Partnership

AltaGas and TransCanada are partners in the ASTC Partnership. Each partner owns a 50 percent share of ASTC Partnership and contributed 50 percent of the \$223.1 million required for the ASTC Partnership to purchase the two Sundance B PPAs from Enron Canada Power Corporation on December 28, 2001. There are two Sundance B PPAs, one for each of Units 3 and 4 at the Sundance Plant. The ASTC Partnership holds the Sundance B PPAs as partnership property, with both partners having an equal interest in each PPA.

The indirect 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to 353 MW of coal-fired generation capacity, as well as to ancillary services from Sundance Units 3 and 4, until December 31, 2020.

The ASTC Partnership started dispatching power effective December 29, 2001. AltaGas maintains the books and records of the ASTC Partnership, including providing accounting services. TransCanada manages daily operations, including the dispatch of power into the Pool. AltaGas and TransCanada are each responsible for managing the market risk associated with their individual shares of the power generation capacity.

The Sundance B Plant

TransAlta owns the coal-fired Sundance Plant, which is located approximately 70 km west of Edmonton, Alberta. The Sundance Plant consists of Units 1 through 6. An auction conducted on August 24, 2000 grouped the units into three plants: Sundance A Plant - Units 1 and 2, Sundance B Plant - Units 3 and 4, and Sundance C Plant - Units 5 and 6. Sundance B Plant has been operating since 1976 (Unit 3) and 1977 (Unit 4).

The Sundance Plant is connected to the Alberta Interconnected Electric System, which allows access to markets in Alberta, British Columbia, Saskatchewan and the United States.

The Sundance B Plant - Power Sales

Revenue from the sale of power is largely driven by target availability, hedge prices (for the portion of capacity that is hedged) and Pool prices (for the portion of capacity that is not hedged). The inter-relationship of production, Pool prices and cost of sales is specified in the PPAs. Generally, the ASTC Partnership will be compensated when power production is less than target levels, at a rate based on the previous 30-day average Pool price, as described in more detail later in this section. AltaGas recognizes its share of revenue based on target production levels, with any increase or decrease relative to target credited or charged to operating expenses.

Under the Sundance B PPAs, the ASTC Partnership holds the rights to the power capacity and ancillary services from Units 3 and 4 of the Sundance Plant. Day-to-day operation requires the ASTC Partnership to communicate the volume of power available and the price of the power to the AESO. The ASTC Partnership is obligated to pay TransAlta a price which is intended to cover TransAlta's capital and operating costs as determined by formulas in the Sundance B PPAs. The majority of the ASTC Partnership's cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Pool trading charges.

Each of Units 3 and 4 has a contracted capacity of 353 MW. In September 2007, TransAlta increased the capacity of unit 4 by 53 MW pursuant to their rights under the PPA. TransAlta provided all of the capital, is responsible for all operating costs and is entitled to all benefits associated with this increased capacity, although ASTC earns a fee associated with the administration of the agreement. The Sundance B PPAs recognize that the plants will not produce at 100 percent capacity all of the time. TransAlta is obligated to provide AltaGas financial compensation if actual generation of electricity from Units 3 and 4 falls below a specified target level, which was 86 percent of contracted capacity in 2007. This is accomplished by a monthly payment based on the difference between actual availability and target availability, multiplied by RAPP. Similarly, if Units 3 and 4 produce above target, then ASTC is obligated to pay TransAlta based on the difference between actual availability and target availability, multiplied by RAPP. ASTC pays transmission charges based on actual power delivered. During these under or over-generation periods AltaGas has financial exposure to the difference between the Alberta spot price and RAPP on the difference between volumes generated and target availability. The financial exposure may be positive or negative depending on the difference between the current Pool price and RAPP.

TransAlta is an experienced operator of coal-fired electrical generation facilities and has financial incentives to operate the Sundance B plant efficiently and at high levels of electricity generation. The plant uses coal from the adjacent Highvale Mine, which is anticipated to have sufficient reserves for the expected fuel requirements of the Sundance B Plant beyond the life of the Sundance B PPAs. The coal price formula, which is pre-defined in the PPAs, is subject to inflationary indices and is not linked to current market prices for coal.

Gas-Fired Peaking Capacity

On September 1, 2004 AltaGas entered into a long-term capital lease with Maxim Power Corp. for 25 MW of gas-fired peaking capacity on four sites in southern Alberta. The capital lease has a 10-year term that commenced September 1, 2004 and includes an option at the end of the initial term to extend the term for 15 years or to purchase the assets. The capital lease requires AltaGas to pay a monthly capacity fee. The operations and maintenance services contract that previously dealt with the peaking facilities expired March 15, 2007 and AltaGas assumed responsibility for operation of the facilities. AltaGas retains 100 percent of the ancillary services and merchant peaking sales revenue.

In Alberta, gas-fired peaking capacity generally provides energy during times of high prices. AltaGas manages the gas requirement and dispatches the units. This 25 MW of gas-fired power capacity provides fuel diversity to AltaGas' power business and provides partial backstopping to outages at Sundance. In addition, due to their quick ramp-up capability, the peaking plants provide revenue from the sale of energy and ancillary services.

In 2007, AltaGas purchased an additional 14.4 MW of gas fired peaking generation, which is currently being installed at the Bantry and Parkland field gathering and processing facilities. These generators will operate in a similar manner as the existing peaking generators, providing additional backstopping to the Sundance B PPAs and earning revenue from

the sale of energy and ancillary services. Upon connection to the electricity grid, the new gas-fired peaking plants will increase AltaGas' peaking capacity by 58 percent and further increase operational flexibility and backstopping to the Sundance B PPA.

Hydroelectric Generation

As part of the Taylor acquisition, AltaGas acquired Taylor's 25 percent interest in Boston Bar Partnership which owns a 7 MW run-of-river hydroelectric facility on Scuzzy Creek, near Boston Bar, British Columbia and which is under a 20-year electricity purchase agreement with B.C. Hydro until 2015. In addition to its interest in Boston Bar Partnership, AltaGas has two additional 10 MW run-of-river plants in development near Boston Bar, B.C. acquired through Taylor: Log Creek and Kookipi Creek. Both the Log Creek and Kookipi Creek projects are supported by 40-year electricity purchase agreements with B.C. Hydro. Development efforts have been focused on the acquisition of all the required regulatory permits as well as the completion of detailed engineering. Both Log Creek and Kookipi are expected to be operational in 2010, provided that the necessary regulatory approvals have been obtained.

In February 2008 AltaGas announced the acquisition of four potential run-of-river hydro projects in British Columbia ranging from 6.5 MW to 24 MW for \$4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia.

Power Generation - Risk Mitigation

The main risk faced in the power business is the fluctuation in the margin between power revenue and the cost for power. This is generally created through changes in power prices, increases in operating costs, changes in transmission rates and reductions in power available for sale mainly due to outage and force majeure events. AltaGas mitigates this risk through disciplined power hedging strategies and portfolio diversity. AltaGas uses hedges to fix the selling prices on a significant portion of its available capacity prior to the beginning of any calendar year. Hedge contracts tend to have terms ranging from one to 36 months. AltaGas also satisfies its own electrical demand requirements of approximately 11 MW and supplies approximately 40 MW to the Energy Services segment, which sells to Alberta power retail customers, for terms of up to 8 years.

During 2007 the average monthly Pool price ranged from a low of \$48.37/MWh in May to a high of \$155.73/MWh in July. The average all-hours Pool price for 2007 was \$66.84/MWh, compared to \$80.48/MWh for 2006. The average sales price received by AltaGas for 2007 was \$68.59/MWh, compared to \$69.26/MWh during 2006. AltaGas has sold approximately two-thirds of its power forward for 2008 and a small portion for 2009 through 2014.

The following chart provides a summary of power prices and volumes for the last two years.

Power Prices and Volumes	2007	2006
Volume of power sold (GWh)	2,661	2,878
Average price received on the sale of power (\$/MWh) ⁽¹⁾	68.59	69.26
Alberta Power Pool average spot price (\$/MWh) ⁽¹⁾	66.84	80.48

(1) Annual average.

In the event of any force majeure related to the Sundance B PPAs that results in permanent destruction of the units, ASTC is entitled to a termination payment from the Balancing Pool equal to its portion of the net present value of the amortized Sundance B PPAs' purchase price to that date. AltaGas has further minimized the risk of a force majeure event by diversifying its supply over two independent baseload Sundance B units, acquiring 25 MW of gas-fired peaking capacity, acquiring an additional 14.4 MW of gas-fired peaking capacity that will be in service in mid-2008 and executing independent backstopping arrangements with external counterparties to supply electricity in the event of a force majeure. In addition, delivery obligations for certain hedges are suspended during outages.

A part of AltaGas' business portfolio risk mitigation strategy is geographic and fuel type diversification. AltaGas, through its interest in BMWLP, is constructing the Bear Mountain Wind Park in B.C with approximate capacity of 100 MW. In addition, it is also pursuing ownership of wind power and other renewable energy projects in western Canada and the United States through GreenWing.

Power Generation - Competition

All of the power produced in Alberta is currently sold into the Pool, which operates an open market for the exchange of electricity and is run by the AESO. The AESO establishes the power price based on offers from Pool participants using a uniform pricing model whereby the marginal unit establishes the price for all generators. AESO system controllers sort

the offers by price into a merit order beginning with the lowest priced offer, thereby defining a supply curve for each hour. By matching energy supply with demand, the Pool establishes a uniform hourly market price, which is published on the AESO's website.

In Alberta, coal-fired electrical generation, which is generally produced at a lower cost than gas-fired electrical generation, is a baseload source of supply, while gas-fired units tend to set the marginal price. Management is not aware of any significant increases in power generation capacity in Alberta in the next several years and therefore expects natural gas-fired electricity to continue to influence the marginal price in Alberta.

The Sundance plant is one of the lowest-cost power producers in Alberta and therefore among the lowest in the dispatch merit order. AltaGas does not expect this situation to change with the addition of new capacity on the grid. In the near-term, the tightening reserve margin should lead to higher power prices, which will be advantageous for AltaGas' existing coal and gas peaking facilities.

ENERGY SERVICES

AltaGas' Energy Services segment contributed net revenue of \$20.9 million for the year ended December 31, 2007, representing approximately 6 percent of the Trust's total net revenue before intersegment eliminations. In 2007 AltaGas invested \$9.3 million in growth capital in the Energy Services segment.

Business Description

The Energy Services segment consists of two main components: an energy management business and a gas services business. This segment also included a small portfolio of oil and gas production assets that were sold in May 2007.

Energy Management

The energy management business consists of providing energy consulting and supply management services and arranging natural gas and power supply for non-residential end-users. Since January 1, 2007 AltaGas' energy management services have been provided under the brand name "ECNG Energy" and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Burnaby, British Columbia.

The majority of the energy management business' fee-for-service revenues are based on one-to-three-year evergreen contracts, with some extending as far as eight years. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives. The energy management business also manages electricity supplies for AltaGas' internal power demand in the Field Gathering and Processing and Extraction and Transmission segments and sells power to industrial and commercial end-users, thereby providing a longer-term market for hedging power sales.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-use customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

The gas services business supports the operations of the Field Gathering and Processing, Extraction and Transmission and Power Generation segments and buys and resells natural gas, transportation and storage. The gas services business contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas' transmission pipelines, providing gas control services to balance gas flows. The gas services business markets gas for Field Gathering and Processing customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' gas-fired peaking plants.

In addition to supporting the other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions and managing potential credit exposures. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has been successful in achieving positive margins while providing improved netbacks for producers.

Energy Services - Strategy

The Energy Services segment provides agency advisory services to energy end-users in the commercial, institutional, small industrial and agricultural sectors and locks in margin through the buying and selling of natural gas, transportation and storage. The segment also provides value added services to the Field Gathering and Processing, Extraction and Transmission and Power Generation segments and their customers by capitalizing on its in-depth knowledge of the energy markets to optimize AltaGas' infrastructure and enhance value.

The Energy Services segment's business strategy is to:

- Maximize profitability of its existing business:
 - Identify opportunities for increased synergies and value across AltaGas' infrastructure and services to increase profitability;
 - Create new service offerings and build on national brand development;
 - Increase market penetration of national energy management services in natural gas and electricity;
 - Manage credit and market risk within the risk tolerances established by the Board of Directors; and
 - Increase cost efficiency and improve competitive advantage through common processes and marketing efforts;
- Grow Energy Services infrastructure:
 - Add physical infrastructure such as gas storage capacity.

Energy Services - Opportunities

The key value driver in the Energy Services segment is the services provided to the other infrastructure based business segments. The Energy Services segment provides gas control and gas supply contracting services to the Field Gathering and Processing, Extraction and Transmission and Power Generation segments. AltaGas' strategy is to identify additional opportunities to enhance the value of its infrastructure through transactions and support services. This includes identifying opportunities to increase margins earned in transmission, maintain the cost-effective flow of gas through extraction plants and increase services provided to producers.

Oil and Natural Gas Production

AltaGas is not in the business of exploration and development of natural gas reserves, as it chooses not to compete with producers flowing natural gas through its gathering and processing systems. However, in connection with larger acquisitions of gathering and processing facilities, AltaGas had accumulated a portfolio of oil and natural gas production assets. The portfolio was non-core to AltaGas' operations and was sold effective May 31, 2007.

Energy Services - Customers

AltaGas has more than 1400 energy management service contracts. Customer retention rates are over 95 percent. These customers are commercial, industrial, agricultural and institutional end-users in Ontario, Alberta, B.C., Quebec, New Brunswick and Manitoba. The AltaGas energy management business arranges natural gas and electricity supply on behalf of its customers through an array of qualified suppliers, including AltaGas. The energy management business sources gas and power supply from third-party suppliers and AltaGas.

In its gas services business, AltaGas buys natural gas from a wide array of suppliers including wholesale marketing companies and producers and sells natural gas to other wholesale marketing companies and retail end-users.

No Energy Services customer represented more than 8 percent of consolidated revenue during 2007.

Energy Services - Competition

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers.

CORPORATE INVESTMENTS

AltaGas makes investments where it considers it to be prudent to do so and where it sees an opportunity to create value. The resulting investments and related revenues and expenses not directly identifiable with the operating segments are reported in the Corporate segment. The Corporate segment contributed net revenue of \$6.2 million for the year ended December 31, 2007, representing approximately 2 percent of the Trust's total net revenue before intersegment eliminations. At December 31, 2007 AltaGas' investment in public and private entities was \$56.6 million.

AltaGas owned 4,027,585 limited partnership units or approximately 8.9 percent of Taylor at December 31, 2007. Additionally, AltaGas holds shares of AltaGas Utility Group Inc., which is the result of the spin-out of AltaGas' natural gas distribution business in November 2005. AltaGas held 1,606,594 common shares, or 19.6 percent, of Utility Group on December 31, 2007. Utility Group is accounted for on an equity basis. Effective second quarter 2007, AltaGas reduced its influence over Taylor, and changed the accounting for its interest from an equity basis to the cost method.

On November 29, 2007 the Trust, indirectly through AltaGas LP #1, offered to acquire all of the outstanding limited partnership units of Taylor NGL Limited Partnership on the basis of, at the election of the holder: (a) \$11.20 in cash; (b) 0.42 of a Trust unit; or (c) a combination of Exchangeable units and Trust units, subject to certain conditions and adjustments. On January 10, 2008 the Trust completed the acquisition of Taylor. See "Development of the Trust – Significant Acquisitions".

DESCRIPTION OF THE TRUST

The Trust is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to the Declaration of Trust. See "AltaGas Income Trust" and "Declaration of Trust and Description of Units". The Trust's operations and activities are restricted but include among other things: acquiring, investing in, holding, transferring, disposing of and otherwise dealing with securities of whatever nature or kind of, or issued by, Holding Trust, the General Partner, AltaGas Ltd. or any associate or affiliate of any thereof, or of, or issued by, any other corporation, partnership, trust or other person involved, directly or indirectly, in the business of, or the ownership, lease or operation of assets or property in connection with, gathering, processing, transporting, extracting, buying, storing or selling petroleum, natural gas, NGLs or other related products, power or other forms of energy and related businesses and such other investments as the Trustee may determine, and to borrow funds and issue debt securities, directly or indirectly, for that purpose and enter into hedging arrangements in relation thereto; engaging in all activities ancillary or incidental to any of these activities; and undertaking such other activities or taking such actions including investing in securities as shall be approved by the Trustee from time to time, provided that the Trust shall not, in any event, undertake any activity, take any action, or make any investment which would result in the Trust not being considered a "unit trust" or a "mutual fund trust" for purposes of the Tax Act or the Trust units being considered "foreign property" for the purposes of the Tax Act or the Trust itself being liable for any tax under Part XI of the Tax Act.

MANAGEMENT OF THE TRUST

THE TRUSTEE

The following is a summary which does not purport to be complete of the material provisions of the Declaration of Trust as they relate to the Trustee. Reference is made to the Declaration of Trust for the full text of its provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

The Declaration of Trust provides that the assets and affairs of the Trust are subject to the power, control and authority of the Trustee. Computershare Trust Company of Canada is the Trust's Trustee and also acts as transfer agent and registrar for the Trust units. The Trustee's initial appointment was until the third annual meeting of unitholders following the effective date of the Arrangement. The Trustee was reappointed at such meeting by the unitholders for a further three-year term expiring in 2010. Thereafter, the unitholders shall reappoint or appoint a successor to the Trustee every three years following the reappointment or appointment of the successor to the Trustee.

The Trustee may be removed by notice in writing delivered by AltaGas Ltd. or the General Partner to the Trustee in certain circumstances. The Trustee may also be removed by ordinary resolution of the unitholders with or without cause.

Powers of the Trustee

Without in any way limiting the general power and authority over the assets and affairs of the Trust granted to the Trustee, the Trustee has the following specific powers and authorities to do the following or to cause the same to be done, among other things: (a) supervise the activities and manage the investments and conduct the affairs of the Trust; (b) maintain records and provide reports to Trust unitholders; (c) effect payment of distributions to Trust unitholders; (d) invest funds of the Trust; (e) where reasonably required, engage or employ on behalf of the Trust any persons as agents, representatives, administrators, employees or independent contractors in one or more capacities; (f) arrange for the procedures regarding the limitations on non-resident ownership as described under the heading "Declaration of Trust and Description of Units – Limitation on Non-Resident Ownership", (g) except as prohibited by applicable law, delegate any of the powers and duties of the Trustee in relation to the Trust as provided in the Declaration of Trust or otherwise to any one or more agents, representatives, administrators, officers, employees, independent contractors or other persons (including but not limited to the General Partner or AltaGas Ltd.) without liability to the Trustee, except as provided in the Declaration of Trust, and may, from time to time, with the consent of the General Partner, change the administrator of the Trust; (h) enter into or perform the obligations of the Trust under and in respect of any and all agreements to which the Trust becomes a party; and (i) without limit as to amount, issue any type of debt securities or convertible debt securities and borrow money or incur any other form of indebtedness for the purpose of carrying out the purposes of the Trust or for other expenses incurred in connection with the Trust; and exercise all powers which are necessary or useful to carry on the purpose and activities of the Trust, to promote any of the purposes for which the Trust is formed and to carry out the provisions of the Declaration of Trust.

The Trustee is required to act honestly and in good faith with a view to the best interests of the Trust and in connection therewith to exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

The Trustee has delegated to the General Partner, pursuant to the Delegation Agreement, the power, authority and responsibility of the Trustee in respect of those matters referred to in the Delegation Agreement. See "Management of the Trust - Delegation Agreement". In addition, the Trustee has contracted to AltaGas Ltd. to provide management, administrative and operating support pursuant to the Administration Agreement. See "Management of the Trust - Administration Agreement".

Restrictions on Trustee's Powers

Notwithstanding any of the Trustee's power and authority, the Trustee may not under any circumstances: vote the Holding Trust units, the Trust's securities of the General Partner or, where applicable, the Holding Trust Notes; or vote the Trust's securities of, or permit Holding Trust or the General Partner to vote their interests in, AltaGas LP #1 or AltaGas LP #2; or AltaGas LP #1 to vote its interests in AltaGas LP #2; or AltaGas LP #2 to vote its securities of AltaGas Ltd., to authorize:

- (a) any sale, lease or other disposition of all or substantially all of the assets of the General Partner, Holding Trust, AltaGas LP #1, AltaGas LP #2 or AltaGas Ltd., except in conjunction with an internal reorganization or a pledge to secure indebtedness incurred in carrying out the purposes of the Trust;
- (b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving Holding Trust, AltaGas LP #1, AltaGas LP #2 or AltaGas Ltd., except in conjunction with an internal reorganization;
- (c) any material amendment to the Holding Trust Note Indenture, other than an amendment which is not prejudicial to the Trust;
- (d) the winding-up, liquidation or dissolution of the General Partner, Holding Trust, AltaGas Ltd. or (unless all of such limited partnership interests therein are owned directly or indirectly by the Trust) AltaGas LP #1 or AltaGas LP #2 prior to the end of the term of the Trust; or
- (e) any material amendment to the Holding Declaration of Trust, the AltaGas LP #1 limited partnership agreement, the AltaGas LP #2 limited partnership agreement, or the articles of the Holding Trust Trustee, the General Partner or AltaGas Ltd., in a manner prejudicial to the Trust,

without the approval of the unitholders by special resolution at a meeting of unitholders called for that purpose. In addition, except as part of an internal reorganization of the direct or indirect assets of the Trust as a result of which the Trust has the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization, the Trustee has no power to:

- (a) sell or otherwise dispose of any securities of the General Partner, Holding Trust units or Holding Trust Notes, except pursuant to a pledge pursuant to the Declaration of Trust or an in specie redemption; or
- (b) sell all or substantially all of the Trust's assets or cause Holding Trust to sell all or substantially all of its assets, or cause Holding Trust to cause any subsidiary thereof to sell all or substantially all of the direct or indirect assets of the Trust, in each case in a single transaction or a series of related transactions, without the approval of the unitholders by special resolution.

Compensation of the Trustee

The Trustee shall be paid by the Trust such fees as may be agreed upon in writing from time to time by the General Partner and the Trustee. As part of the expenses of the Trust, the Trustee may pay or cause to be paid all reasonable fees, costs and expenses incurred in connection with the discharge of any of the duties in the Declaration of Trust, including, without limitation, fees, costs and expenses of AltaGas Ltd. pursuant to the Administration Agreement, auditors, accountants, lawyers, appraisers and other agents, consultants, professional advisors employed by or on behalf of the Trust and the cost of reporting or giving notices to unitholders, including remuneration of the Trustee for services rendered to the Trust in any other capacity (including as transfer agent or Depository).

Liability of Trustee

Except in the event of a breach of the standard of care, diligence and skill required of the Trustee, the Trustee shall not be liable to any unitholder for any action taken in good faith in reliance on any documents that are, prima facie, properly executed; for any depreciation of, or loss to, the Trust incurred by reason of the sale of any security; for the loss or disposition of monies or securities; or for any other action or failure to act including, without limitation, the failure to compel in any way any former trustee to redress any breach of trust or any failure by Holding Trust to perform obligations or pay monies owed to the Trust. If the Trustee has retained an appropriate expert or advisor with respect to any matter connected with its duties under the Declaration of Trust, the Trustee may act or refuse to act based on the advice of such expert or advisor and, notwithstanding any provision of the Declaration of Trust, including, without limitation, the standard of care, diligence and skill required of the Trust, the Trustee shall not be liable for any action or refusal to act based on the advice of any such expert or advisor which it is reasonable to conclude is within the expertise of such expert or advisor to give.

Subject to the standard of care required of the Trustee, neither the Trustee nor any officer, director, employee or agent thereof shall be subject to any liability whatsoever in tort, contract or otherwise, in connection with the Trust assets or the affairs of the Trust, including, without limitation, in respect of any loss or diminution in value of any Trust assets to the Trust or to the unitholders or to any other person for anything done or permitted to be done by the Trustee. The Trustee shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust arising out of anything done or permitted or omitted to be done in respect of the execution of the duties of the office of Trustee for or in respect of the affairs of the Trust. No property or assets of the Trustee, owned in its personal capacity or otherwise, will be subject to any levy, execution or other enforcement procedure with regard to any obligations under the Declaration of Trust or under any other related agreements. No recourse may be had or taken, directly or indirectly, against the Trustee in its personal capacity. The Trust shall be solely liable therefore and resort shall be had solely to the Trust assets for payment or performance thereof.

DELEGATION AGREEMENT

The following is a summary which does not purport to be complete of the material provisions of the Delegation Agreement and the Declaration of Trust. Reference is made to the Delegation Agreement and Declaration of Trust for the full text of its provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

Pursuant to the Declaration of Trust and the Delegation Agreement the Trustee is authorized to, and may, delegate to the General Partner the power, authority and responsibility to make all decisions required to be made by the Trustee from time to time in relation to the Trust including, without limitation the power, authority and responsibility for any and all matters referred to in the Delegation Agreement.

Pursuant to the terms of the Delegation Agreement, the Trustee has delegated to the General Partner the responsibility for, among other things: (a) undertaking responsibility to make all determinations, and take, or cause to be taken, all such actions as relate to (i) the determination of distributions, (ii) redemption of Trust units, (iii) compliance with the Declaration of Trust with respect to non-resident ownership of Trust units, (iv) the acquisition of Trust assets by the Trust; (v) any offering of Trust units or other securities; (b) securing bank financing or refinancing; (c) approving the financial statements of the Trust; (d) approving all information to which unitholders are entitled; (e) undertaking and performing all acts and making all decisions as would be required by applicable law or desirable of an audit committee or other applicable committee of the Trust; (f) undertaking all matters in connection with any take-over bid, merger, amalgamation, arrangement, reorganization, recapitalization, purchase or repurchase of any securities or assets of any person, any business combination, or any other similar transaction involving the Trust; and (g) doing all such other acts and things as may be incidental to or required in connection with the foregoing.

The Delegation Agreement continues in full force and effect until such time as the first of the following occurs: (a) the Trust or the General Partner terminates the Delegation Agreement by notice to the other parties to the Delegation Agreement, with termination to become effective 30 days after the receipt of such notice by the last of the parties; (b) the parties mutually agree in writing to terminate the Delegation Agreement; or (c) the Trust is terminated pursuant to the Declaration of Trust.

Expenses

Pursuant to the Delegation Agreement, generally, all costs, charges and expenses reasonably incurred by the General Partner and the Board of Directors in carrying out the General Partner's obligations and duties under the Delegation Agreement in connection with the provision and performance of the services delegated thereunder (including, without limitation, salary, wages, and other forms of compensation paid to employees engaged in rendering the services to be provided thereunder and/or management fees paid to management entities which might be engaged to provide such services) shall be payable by the Trust out of the Trust's assets.

ADMINISTRATION AGREEMENT

The following is a summary which does not purport to be complete of the material provisions of the Administration Agreement and the Declaration of Trust. Reference is made to the Administration Agreement and Declaration of Trust for the full text of their provisions and a complete description, a copy of which has been filed on SEDAR at www.sedar.com.

The Trustee has delegated to AltaGas Ltd. certain powers and duties expressly provided for in the Declaration of Trust and in the Administration Agreement, including the power to further delegate administration of the Trust. Generally, AltaGas Ltd. provides administrative and support services to, and is responsible for the management and general administration of, the affairs of the Trust, and pursuant to the Administration Agreement, among other things: (a) undertakes any matters required to be performed by the Trustee not otherwise delegated and provides all services as may be necessary or as requested by the Trustee for the administration of the Trust; (b) prepares all documents and makes all necessary determinations necessary for the discharge of the Trustee's obligation; (c) retains and monitors organizations serving the Trust; (d) authorizes and pays operation expenses and negotiates contracts with service providers; (e) provides office space and related equipment and services; (f) subject to the direction and approval of the General Partner, (i) deals with banks and other lenders, (ii) prepares and provides financials statements and tax information to unitholders, (iii) computes, determines and makes distributions to unitholders and administers reinvestment and similar plans, (iv) prepares such disclosure documents as are required under applicable securities legislation in respect of offers to acquire or responses thereto and (v) provides all information to which unitholders are entitled; (g) ensures compliance by the Trust with all agreements and applicable securities legislation; (h) submits all tax returns and filings; (i) provides investor relations services to the Trust; (j) ensures the Trust takes appropriate steps to remain a "mutual fund trust"; (k) calling and holding meetings of unitholders; (l) takes all steps necessary to issue securities of the Trust, as directed by the General Partner; (m) attends to all administrative and other matters in connection with redemptions of Trust units; (n) obtaining and maintaining liability insurance for certain directors and officers; (o) undertakes, manages and prosecutes all proceedings in respect of governmental authorities under the direction of the General Partner; (p) prepares any documents to qualify the sale of securities of the Trust, subject to the approval of the General Partner; and (q) promptly notifies the Trust of any event that might have a material adverse effect on the affairs of the Trust.

AltaGas Ltd. provides similar administrative services to the foregoing to each of Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2 pursuant to the Administration Agreement, modified as necessary to take into account the nature of the entity and the terms, conditions and limitations of the Holding Declaration of Trust, the constating documents of the General Partner, AltaGas LP #1 Limited Partnership Agreement and AltaGas LP #2 Limited Partnership Agreement, respectively.

In the conduct of its duties pursuant to the Administration Agreement, AltaGas Ltd. has full right, power and authority to execute and deliver all contracts, leases, licenses and other documents and agreements, to make applications and filings with governmental authorities and take such other actions as it considers appropriate in connection with the business of the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, respectively.

AltaGas Ltd. must exercise the powers and discharge the duties conferred under the Administration Agreement honestly, in good faith and in the best interests of the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2 and exercise the degree of care, diligence and skill that a reasonably prudent administrator in Canada having responsibilities of a similar nature would exercise in comparable circumstances.

Expenses

Pursuant to the Administration Agreement, AltaGas Ltd. is reimbursed by each of the Trust, Holding Trust, AltaGas LP #1, AltaGas LP #2 and the General Partner, without duplication, for such of the expenses (including, without limitation, salary, wages and other forms of compensation paid to employees engaged in rendering services under the Administration Agreement, and out-of-pocket expenses) incurred by AltaGas Ltd. as are, in the opinion of AltaGas Ltd., acting reasonably, reasonably allocable respectively thereto.

DECLARATION OF TRUST AND DESCRIPTION OF UNITS

The following is a summary which does not purport to be complete of the material attributes and characteristics of the Trust units and special voting units and certain provisions of the Declaration of Trust. Reference is made to the Declaration of Trust for the full text of its provisions and a complete description of the Trust units and special voting units, a copy of which has been filed on SEDAR at www.sedar.com.

TRUST UNITS

An unlimited number of Trust units may be created and issued pursuant to the Declaration of Trust. Each Trust unit entitles the holder thereof to one vote at any meeting of the unitholders or in respect of any written resolution of unitholders and represents an equal undivided beneficial interest in any distribution from the Trust (whether of income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All Trust units shall rank among themselves equally and rateably without discrimination, preference or priority, whatever may be the actual date or terms of issue thereof. Each Trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust units held by such holder. See "Declaration of Trust and Description of Units – Trust Unit Redemption Right".

SPECIAL VOTING UNITS

The Declaration of Trust allows for the creation of special voting units which enables the Trust to provide voting rights to holders of exchangeable securities. A Special Voting Unit was issued pursuant to the Arrangement to enable the holders of Exchangeable units issued by AltaGas LP #1 and AltaGas LP #2 to vote at meetings of unitholders. The Special Voting Unit created and issued pursuant to the Arrangement was issued to the Voting and Exchange Trustee. The holder of a special voting unit, including in respect of the Special Voting Unit, the Voting and Exchange Trustee, is not entitled to any interest or share in the distributions or net assets of the Trust and is only entitled to such number of votes at meetings of unitholders as is equal to the number of Trust units into which the exchangeable securities to which such special voting unit relates are exchangeable or convertible.

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued the Special Voting Unit to the Voting and Exchange Trustee for the benefit of every person who received Exchangeable units pursuant to the Arrangement. The Voting and Exchange Trustee is obligated to vote the Special Voting Unit at meetings of unitholders pursuant to the instructions of the holders of Exchangeable units. However, if no instructions are provided by the holders of Exchangeable units, the votes associated therewith in the Special Voting Unit will be withheld from voting.

The special voting units will be subject to such other rights and limitations as may be determined by the Trustee at the time of issuance of the special voting unit. The Declaration of Trust provides that upon the exchange of Exchangeable units for Trust units, the entitlement to vote pursuant to the Special Voting Unit will be eliminated in respect of those Exchangeable units.

EXCHANGEABLE UNITS

AltaGas LP #1 is authorized to issue an unlimited number of AltaGas LP #1 B units. Similarly, AltaGas LP #2 is authorized to issue an unlimited number of AltaGas LP #2 B units. AltaGas LP #1 and AltaGas LP #2 issued AltaGas LP

#1 B units and AltaGas LP #2 B units, respectively, to eligible AltaGas Services' securityholders in consideration for their common shares in the capital of AltaGas Services pursuant to the Arrangement.

Each Exchangeable unit is exchangeable for a Trust unit on a one-for-one basis at any time at the option of the holder, entitles the holder thereof to receive non-interest bearing loans from AltaGas LP #1 or AltaGas LP 2, as the case may be, in an amount in cash equal to the cash distributions made by the Trust on a Trust unit, entitles the holder thereof to direct the Voting and Exchange Trustee to vote the Special Voting Unit at all meetings of unitholders, entitles the holder thereof to vote separately as a class in respect of proposals to add to, change or remove any right, privilege, restriction or condition attaching to the Exchangeable units or in respect of any other amendment to the applicable limited partnership agreement which will have an adverse impact on the holders of such Exchangeable units, will not be transferable except to eligible transferees, and AltaGas LP #1 or AltaGas LP #2, as the case may be, will be entitled to acquire all of the Exchangeable units in exchange for Trust units in certain specified circumstances, including there being outstanding fewer than 750,000 AltaGas LP #1 B units or 1,000,000 AltaGas LP #2 B units or in the event of certain transactions which may involve a change of control of the Trust.

ISSUANCE OF UNITS

The Declaration of Trust provides that Trust units, including exchangeable securities, rights, warrants, options or other securities convertible into or exchangeable for Trust units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee may determine. The Declaration of Trust also provides that the Trustee may authorize the creation and issuance of any type of debt securities or convertible debt securities of the Trust from time to time on such terms and conditions to such persons and for such consideration as the Trustee may determine.

DISTRIBUTIONS

Pursuant to the Declaration of Trust, the Trust is required to make cash distributions to unitholders each calendar month (or such other periods as may be determined by the Trustee) of all or any part of the Cash Flow of the Trust. Cash received by the Trust from its subsidiaries will be managed by the General Partner, giving consideration to the consolidated net income of the Trust, the consolidated growth and maintenance capital requirements of the Trust, the consolidated debt repayment requirements of the Trust and other factors. The intent of the General Partner is to maximize the cash received by the Trust from its subsidiaries giving consideration to these various factors.

Distributions in respect of a month will be paid to unitholders of record as at the close of business on each determined distribution record date. The distribution for any month will be paid on the determined distribution payment date. In addition, the Declaration of Trust provides that, if necessary, on December 31st of each year, the Trust will distribute an additional amount such that the Trust will not be liable for ordinary income taxes for such year.

PURCHASE OF UNITS

The Trust may from time to time purchase for cancellation some or all of the Trust units (or other securities of the Trust which may be issued and outstanding from time to time) in the market, by private agreement or upon any recognized stock exchange on which such Trust units are traded or pursuant to tenders received by the Trust upon request for tenders addressed to all holders of record of Trust units, provided in each case that the Trustee has determined that such purchases are in the best interests of the Trust. Any such purchases may constitute an "issuer bid" under Canadian provincial securities legislation and must be conducted in accordance with the applicable requirements thereof. A unitholder will not have the right at any time to require the Trust to purchase such unitholder's Trust units.

TRUST UNIT REDEMPTION RIGHT

Trust units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of a duly completed and properly executed notice requesting the Trust to redeem Trust units. Upon receipt of the notice to redeem Trust units by the Trust, the holder thereof shall thereafter cease to have any rights with respect to the Trust units tendered for redemption (other than to receive the redemption payment therefor unless the redemption payment is not made as required) including the right to receive any distributions thereon which are declared payable on a date subsequent to the day of receipt by the Trust of the notice requesting redemption.

Cash Redemption

Upon receipt by the Trust of the notice to redeem Trust units, the tendering unitholder will thereafter be entitled to receive the Market Redemption Price, which is equal to the lesser of: (a) 90 percent of the Market Price per Trust unit on the principal stock exchange on which the Trust units are listed (or, if the Trust units are not listed on any such exchange, on the principal market on which the Trust units are quoted for trading) during the period of the last 10 trading days immediately prior to the date on which the Trust units were tendered for redemption; and (b) 100 percent of the Closing

Market Price on the principal stock exchange on which the Trust units are listed (or, if the Trust units are not listed on any such exchange, on the principal market on which the Trust units are quoted for trading) on the date that the Trust units were tendered for redemption.

The aggregate Market Redemption Price payable by the Trust in respect of the Trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment within five business days after the end of the calendar month in which the Trust units were tendered for redemption.

Trust unitholders will not receive cash upon the redemption of their Trust units if:

- (a) The total amount payable by the Trust in respect of such Trust units and all other Trust units tendered for redemption in the same calendar month exceeds \$50,000; provided that the Trustee may, in its sole discretion, waive such limitation in respect of all Trust units tendered for redemption in any calendar month. If this limitation is not so waived, the Trust units tendered for redemption in such calendar month shall be redeemed for cash based on the Market Redemption Price and, unless any applicable regulatory approvals are required, by a distribution in specie of the Trust's assets, based on the in specie Redemption Price (as defined below), which may include Series 3 Notes issued by Holding Trust (Series 3 Notes) or other assets held by the Trust, on a pro rata basis. See "Holding Trust – Holding Trust Notes";
- (b) At the time such Trust units are tendered for redemption, the outstanding Trust units are not listed for trading on the TSX or traded or quoted on any stock exchange or market which the Trustee considers, in its sole opinion, provides representative fair market value prices for the Trust units;
- (c) The normal trading of the Trust units is suspended or halted on any stock exchange on which the Trust units are listed for trading or, if not so listed, on any market on which the Trust units are quoted for trading, on the date that such Trust units tendered for redemption were tendered to the Trust for redemption or for more than five trading days during the 10-day trading period prior to the date on which such Trust units were tendered for redemption; or
- (d) The redemption of Trust units will result in the delisting of the Trust units on the principal stock exchange on which the Trust units are listed.

In Specie Redemption

If a cash redemption is not available for Trust units tendered for redemption by a unitholder, then such unitholder will, instead of the Market Redemption Price per Trust unit, be entitled to receive a price per Trust unit (the in specie Redemption Price) equal to the fair market value of a Trust unit as determined by the Trustee in its sole discretion. The in specie Redemption Price will, subject to all necessary regulatory approvals, be paid and satisfied by way of a distribution in specie of Trust assets, which may include Series 3 Notes or other assets held by the Trust (other than Holding Trust units), as determined in the sole discretion of the Trustee.

The aggregate in specie Market Redemption Price payable by the Trust in respect of the Trust units surrendered for redemption during any calendar month shall be paid by the transfer, to or to the order of the Trust unitholder who exercised the right of redemption within five business days after the end of the calendar month in which the Trust units were tendered for redemption, of Trust assets.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust units to dispose of their Trust units. Series 3 Notes which may be distributed in specie to Trust unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Series 3 Notes. Series 3 Notes will not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

MEETINGS OF UNITHOLDERS

The Declaration of Trust provides that meetings of unitholders must be called and held for, among other matters, the election of the Board of Directors, the appointment or removal of the auditors of the Trust, the approval of amendments to the Declaration of Trust (except as described under "Declaration of Trust and Description of Units - Amendments to the Declaration of Trust"), the sale of all or substantially all of the Trust's assets, the dissolution or termination of the Trust and the appointment or removal of the Holding Trust Trustee. Meetings of unitholders will be called and held annually for, among other things, the election of the Board of Directors and the appointment of the auditors of the Trust.

A meeting of unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 5 percent of all votes entitled to be voted at a

meeting of unitholders (including the votes attached to Exchangeable units by virtue of the Special Voting Unit) by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Subject to the Voting and Exchange Trust Agreement, only unitholders of record may attend and vote at all meetings of unitholders either in person or by proxy and a proxyholder need not be a unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5 percent of the votes attaching to all outstanding Trust units and the Special Voting Unit shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the Special Voting Unit shall be regarded as representing outstanding Trust units equivalent in number to the number of Exchangeable units represented by proxy by the Voting and Exchange Trustee at such meeting.

The Declaration of Trust contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of unitholders in accordance with the requirements of applicable laws.

LIMITATION ON NON-RESIDENT OWNERSHIP

In order to ensure that the Trust qualifies as a "mutual fund trust" under the Tax Act, the Declaration of Trust provides, in part, that:

- (a) The General Partner shall: (i) prior to the consummation of any transaction involving the acquisition by the Trust of any properties or assets other than securities of the General Partner or Holding Trust; (ii) prior to any material modification to the Trust other than as contemplated by (i); (iii) promptly following any proposed amendment to paragraph 132(7)(a) of the Tax Act or the publication of any administrative bulletin or other notice of interpretation relating to the interpretation or application of such section; or (iv) otherwise at any time when requested by the Trustee, obtain an opinion of counsel confirming whether the Trust is, at the date thereof and following such transaction or event (which in the case of (iii) shall mean the coming into effect of the amendment or change of interpretation), entitled to rely on paragraph 132(7)(a) of the Tax Act (or any successor provision thereto) for purposes of qualifying as a "mutual fund trust" under the Tax Act;
- (b) If at any time the Board of Directors determines, in its sole discretion, or becomes aware, pursuant to (a) above or otherwise, that the Trust's ability to continue to rely on paragraph 132(7)(a) of the Tax Act (or any successor provision thereto) for purposes of qualifying as a "mutual fund trust" thereunder is in jeopardy, then forthwith after such determination:
 - (i) The Trust shall not be maintained primarily for the benefit of non-residents and it shall be the sole responsibility of the General Partner to monitor the holdings by non-residents; and
 - (ii) The General Partner shall take such steps as are necessary or desirable to ensure that the Trust is not maintained primarily for the benefit of non-residents;
- (c) The General Partner may, at any time and from time to time, in its sole discretion, request that the Trustee make reasonable efforts, as practicable in the circumstances, to obtain declarations as to beneficial ownership of Trust units, perform residency searches of Trust unitholders and holders of Exchangeable units and beneficial Trust unitholders and holders of Exchangeable units mailing address lists and take such other steps specified by the General Partner, at the cost of the Trust, to determine or estimate as best possible the residence of the beneficial owners of Trust units; and
- (d) If at any time the Board of Directors, in its sole discretion, determines that it is in the best interest of the Trust, the General Partner, notwithstanding the ability of the Trust to continue to rely on subsection 132(7)(a) of the Tax Act for the purpose of qualifying as a "mutual fund trust" under the Tax Act or otherwise, may:
 - (i) Require the Trustee to refuse to accept a subscription for Trust units from, or issue or register a transfer of Trust units to, a person unless the person provides a declaration to the Trust that the Trust units to be issued or transferred to such person will not when issued or transferred be beneficially owned by a non-resident;
 - (ii) To the extent practicable in the circumstances, send a notice to registered holders of Trust units which are beneficially owned by non-residents, chosen in inverse order to the order of acquisition or registration of such Trust units beneficially owned by non-residents or in such other manner as the General Partner may consider equitable and practicable, requiring them to

sell their Trust units which are beneficially owned by non-residents or a specified portion thereof within a specified period of not less than 60 days. If the Trust unitholders receiving such notice have not sold the specified number of such Trust units or provided the General Partner with satisfactory evidence that such Trust units are not beneficially owned by non-residents within such period, the General Partner may, on behalf of such registered Trust unitholders, sell such Trust units and, in the interim, suspend the voting and distribution rights attached to such Trust units and make any distribution in respect of such Trust units by depositing such amount in a separate bank account in a Canadian chartered bank (net of any applicable taxes). Any sale shall be made on any stock exchange on which the Trust units are then listed and, upon such sale, the affected holders shall cease to be holders of Trust units so deposited of and their rights shall be limited to receiving the net proceeds of sale, and any distribution in respect thereof deposited as aforesaid, net of applicable taxes and costs of sale, upon surrender of the Trust Certificates representing such Trust units;

- (iii) Delist the Trust units from non-Canadian stock exchanges; and/or
- (iv) Take such other actions as the Board of Directors determines, in its sole discretion, are appropriate in the circumstances that will reduce or limit the number of Trust units held by non-resident Trust unitholders to ensure that the Trust is not maintained primarily for the benefit of non-residents.

AMENDMENTS TO THE DECLARATION OF TRUST

The Trustee may, without the consent, approval or ratification of any of the unitholders, amend the Declaration of Trust at any time:

- (a) For the purpose of ensuring the Trust's continuing compliance with applicable laws, regulations or policies of any governmental authority having jurisdiction over the Trustee or the Trust;
- (b) In a manner which, in the opinion of the Trustee, provide additional protection for the unitholders;
- (c) In a manner which, in the opinion of the Trustee, is necessary or desirable as a result of changes in Canadian tax laws;
- (d) To remove any conflicts or inconsistencies in the Declaration of Trust or to make minor corrections which are, in the opinion of the Trustee, necessary or desirable and not prejudicial to the unitholders; or
- (e) To change the situs of, or the laws governing, the Trust which, in the opinion of the Trustee is desirable in order to provide unitholders with the benefit of any legislation limiting their liability.

TERM OF THE TRUST

The unitholders may vote by special resolution to terminate the Trust at any meeting of the unitholders duly called for that purpose, following which the Trustee shall commence to wind-up the affairs of the Trust (and shall thereafter be restricted to only such activities).

Unless the Trust is earlier terminated or extended by vote of the unitholders, the Trustee shall commence to wind up the affairs of the Trust on such date as may be determined by the Trustee, being not more than two years prior to the earlier of March 24, 2104 and the date which is one day prior to the date, if any, the Trust would otherwise be void by virtue of any applicable rule against perpetuities then in force in Alberta. In the event that the Trust is wound up, the Trustee will sell and convert into money the assets of the Trust in one transaction or in a series of transactions at public or private sales and do all other acts appropriate to liquidate the property of the Trust, and shall in all respects act in accordance with the directions, if any, of the unitholders (in respect of termination authorized pursuant to a special resolution). After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall, subject to obtaining all necessary regulatory approvals, distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of Trust's assets pro rata among the unitholders.

TAKE-OVER BIDS

The Declaration of Trust contains provisions to the effect that if a take-over bid, as defined under the Securities Act (Alberta), is made for the Trust units and not less than 90 percent of the Trust units (including Trust units issuable upon the conversion, exercise or exchange of any securities exchangeable into Trust units but not including any Trust units

held at the date of the take-over bid by or on behalf of, or issuable to, the offeror or an affiliate or associate of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust units and exchangeable securities held by unitholders who did not accept the take-over bid on the terms offered by the offeror.

HOLDING TRUST

The Holding Declaration of Trust contains provisions substantially similar to those of the Declaration of Trust relating to the Trust, however reference is made to the Holding Declaration of Trust and the Declaration of Trust for the full text of their respective provisions copies of which have been filed on SEDAR at www.sedar.com.

GENERAL

Holding Trust is an unincorporated investment trust established under the laws of Alberta pursuant to the Holding Declaration of Trust. Its activities are restricted but include specifically, among other things: acquiring, investing in, holding, transferring, disposing of and otherwise dealing with securities of whatever nature or kind of, or issued by, AltaGas LP #1, AltaGas LP #2, AltaGas Ltd. or any associate or affiliate of any thereof, or of, or issued by, any other corporation, partnership, trust or other person involved, directly or indirectly, in the business of, or the ownership, lease or operation of assets or property in connection with, gathering, processing, extracting, transporting, buying, storing or selling of petroleum, natural gas, natural gas liquids, and other related products, power or other forms of energy, and related businesses, and such other investments as the Holding Trust Trustee may determine, and borrowing funds and issuing debt securities for such purposes and entering into hedging arrangements in relation thereto; and engaging in all activities ancillary or incidental to any of the foregoing activities and undertaking such other activities or taking such actions including investing in securities as shall be approved by the Holding Trust Trustee from time to time.

As at the date of this Annual Information Form, Holding Trust does not intend to hold securities of any entities other than AltaGas LP #1.

REDEMPTION RIGHT

The right of redemption conferred upon a holder of trust units of Holding Trust by the Holding Declaration of Trust may only be exercised after the holder of trust units of Holding Trust has received written notice from the Holding Trust Trustee that it may exercise that right, such that holders of Holding Trust trust units will not be entitled to redeem their Holding Trust trust units on demand.

CASH DISTRIBUTIONS

Holding Trust makes monthly cash distributions to the Trust of its net monthly cash flow, after satisfaction of its interest obligations on the Holding Trust Notes, if any, and less any estimated cash amounts required for expenses, costs and other obligations of Holding Trust. Such distributions are paid on the day which is the same as the Trust's distribution payment date to enable the Trust to pay its distributions.

If the Holding Trust Trustee determines that Holding Trust does not have cash in an amount sufficient to make payment of the full amount of any distribution, the payment may include the issuance of additional Holding Trust trust units or Holding Trust Notes having a value equal to the difference between the amount of such distribution and the amount of cash which has been determined by the Holding Trust Trustee to be available for the payment of such distribution. The value of each Holding Trust trust unit so issued will be the redemption price thereof and the value of each Holding Trust Note so issued will be the redemption amount thereof as determined pursuant to the Holding Trust Note Indenture.

Any Holding Trust trust units transferred to unitholders pursuant to a distribution in specie may be subject to resale and transfer restrictions and cannot be resold or transferred except as permitted by applicable securities law.

LIMITATION ON NON-RESIDENT OWNERSHIP

Notwithstanding any other provision of the Holding Declaration of Trust, no Holding Trust trust unit may be issued to, held by or transferred to a non-resident.

RESTRICTIONS ON TRANSFER OF HOLDING TRUST UNITS

Notwithstanding any other provision of the Holding Declaration of Trust, no transfer of any Holding Trust trust unit will be made without the consent of the Holding Trust Trustee, which consent may be withheld by the Holding Trust Trustee for any reason.

HOLDING TRUST NOTES

The following is a summary which does not purport to be complete of the material attributes and characteristics of the Holding Trust Notes and certain provisions of the Holding Trust Note Indenture. Reference is made to the Holding Trust Note Indenture for the full text of its provisions and a complete description of the Holding Trust Notes, a copy of which has been filed on SEDAR at www.sedar.com.

The Holding Trust Note Indenture authorizes the creation and issuance of three series of Holding Trust Notes in Canadian Currency: Series 1 Notes; Series 2 Notes; and Series 3 Notes. Each series of Holding Trust Notes consists of an unlimited aggregate principal amount, is issuable in denominations of \$10 and integral multiples of \$10, represents an unsecured debt obligation of Holding Trust and is redeemable pursuant to the provisions of the Holding Trust Note Indenture. The specific characteristics unique to each series of Holding Trust Note are as set forth in the Holding Trust Note Indenture.

Payment Upon Maturity

On maturity, Holding Trust will repay the Holding Trust Notes by paying to the Note Trustee under the Holding Trust Note Indenture in cash an amount equal to the principal amount of the outstanding Holding Trust Notes which have then matured, together with accrued and unpaid interest thereon.

Redemption

The Holding Trust Notes are redeemable at the option of Holding Trust prior to maturity.

Subordination/Security

The Holding Trust Notes rank *pari passu* with one another. However the payment of the principal amount and interest on any of the Holding Trust Notes is expressly subordinated in right of payment to the prior payment in full of all senior indebtedness, being all indebtedness, liabilities and obligations of Holding Trust which, by the terms of the instrument creating or evidencing the same, is not expressed to rank in right of payment in subordination to or *pari passu* with the indebtedness evidenced by the Holding Trust Note Indenture. In addition, any liens held by the Note Trustee or holders of Holding Trust Notes, as well as the rights, remedies and recourses granted to the Note Trustee or holders of Holding Trust Notes, are completely subordinated to any and all liens held at present or in the future by the holders of senior indebtedness notwithstanding any ranking that might otherwise be established by law.

The Holding Trust Note Indenture provides that upon any distribution of the assets of Holding Trust in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to Holding Trust, or in the event of any proceedings for voluntary liquidation or termination or other winding-up of Holding Trust, the holders of all such senior indebtedness will be entitled to receive payment in full (of principal, premium or penalty, if any, and interest) before the holders of the Holding Trust Notes are entitled to receive any payment.

Default

The Holding Trust Note Indenture provides that any of the following shall constitute an event of default:

- (a) If default is made in the payment of any principal due on any of the Holding Trust Notes of any series when the same becomes due under any provision of the Holding Trust Note Indenture or of the Holding Trust Notes as required under Holding Trust Note Indenture and such default shall have continued for a period of 10 business days; or
- (b) If default is made in the payment of any interest due on any of the Holding Trust Notes and such default shall have continued for a period of 15 business days; or
- (c) If default is made in the performance or breach by Holding Trust of any other covenant or agreement under the provisions of the Holding Trust Notes or the Holding Trust Note Indenture which shall continue for 30 days after written notice specifying such default and requiring such default to be remedied shall have been given to Holding Trust by the Note Trustee; or
- (d) If there occurs with respect to any issue or issues of indebtedness of Holding Trust having an outstanding principal amount of \$100 million or more an event of default that has caused the holder thereof to declare such indebtedness to be due and payable prior to its maturity and such indebtedness has not been discharged in full or such acceleration has not been rescinded or annulled within 30 days of such acceleration; or

- (e) If a proceeding or action shall be commenced against Holding Trust, except in certain circumstances, in any court of competent jurisdiction, seeking (i) its reorganization, liquidation, termination or winding-up, or the composition or readjustment of its debts, (ii) the appointment of a receiver, custodian, liquidator or the like of Holding Trust or all or any substantial part of its property, or (iii) similar relief in respect of Holding Trust under any law relating to bankruptcy, insolvency, reorganization, winding up or composition or adjustment of debts, and such proceeding or action shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of 60 or more days, or an order for relief against Holding Trust shall be entered in an involuntary case under the Bankruptcy Act; or
- (f) If Holding Trust shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, examiner, liquidator or the like of itself or of all or any substantial part of its property, (ii) make a general assignment for the benefit of its creditors, (iii) commence a voluntary case under the Bankruptcy Act or any other similar foreign statute, (iv) institute any proceeding or file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, liquidation, termination, winding up or composition or readjustment of debts, (v) fail to contest in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the Bankruptcy Act or any other similar foreign statute, or (vi) take any action for the purpose of effecting any of the foregoing; or
- (g) If a creditor shall have taken possession of all or substantially all of the assets of Holding Trust.

Holding Trust Unit Certificates

As Holding Trust trust units are not intended to be issued or held by any person other than the Trust, registration of interests in, and transfers of, the Holding Trust trust units will not be made through the book entry system administered by the Canadian Depository for Securities Limited. Rather, holders of Holding Trust trust units will be entitled to receive certificates therefore.

MEETINGS OF HOLDING TRUST UNITHOLDERS

An annual meeting of holders of Holding Trust trust units shall be called on a day on or before June 30 in each year, at such time and place as shall be prescribed for the purpose of presenting the audited financial statements of Holding Trust, appointing the auditors of Holding Trust for the ensuing year and transacting such other business as the Holding Trust Trustee may determine or as may properly be brought before the meeting. Notwithstanding the foregoing, a resolution in writing executed by holders of Holding Trust trust units holding more than 66 2/3 percent of the votes attached to Holding Trust trust units at any time will be valid and binding for all purposes.

GENERAL PARTNER

Pursuant to the Delegation Agreement, the General Partner is delegated certain of the Trustee's powers and duties in respect of the business and affairs of the Trust and pursuant to the Unanimous Shareholder Agreement the General Partner is entitled to exercise the powers of the directors of AltaGas Ltd. and any other entities as determined to manage, or supervise the management of, the business and affairs of AltaGas Ltd. See "Management of the Trust – Delegation Agreement" and "Declaration of Trust and Description of Units – Meetings of Unitholders".

The General Partner is the general partner of AltaGas LP #1, AltaGas LP #2, AltaGas Limited Partnership, PremStar Energy Canada Limited Partnership and ECNG Energy. The General Partner is also a party to the Administration Agreement pursuant to which AltaGas Ltd. provides certain administrative services to the General Partner. See "Management of the Trust – Administration Agreement".

DIRECTORS AND OFFICERS

The number of directors of the General Partner is to be determined from time to time by resolution of the Board of Directors. The number of directors currently comprises eight of which seven are independent directors.

The term of office of any director continues until the annual meeting of shareholders of the General Partner next following the director's election or appointment or (if an election or appointment of a director is not held at such meeting or if such meeting does not occur) until the date on which the director's successor is elected or appointed, or earlier if the director dies or resigns or is removed or disqualified, or until the director's term of office is terminated for any other reason in accordance with the constating documents of the General Partner. Pursuant to the Declaration of Trust, the unitholders will annually be entitled to direct the Trustee as to the persons to be elected to the Board of Directors.

The names, municipalities of residence, positions with the General Partner and principal occupations within the last five years of the current directors and officers of the General Partner are set out below.

Name of Director, Municipality of Residence and Position with the General Partner	Principal Occupation During the Past Five Years	Director Since	Securities Beneficially Owned or Controlled ⁽¹⁾
<i>David W. Cornhill</i> ⁽³⁾⁽⁹⁾ Calgary, Alberta, Canada Chairman and Chief Executive Officer	In January 2008, Chairman and Chief Executive Officer. From 2005 through January 2008, Chairman, President and Chief Executive Officer of AltaGas and the General Partner. In 2004, Chairman and Chief Executive Officer of AltaGas and the General Partner. Chairman and Chief Executive Officer of AltaGas Services from 2003 to 2004. Prior thereto President and Chief Executive Officer of AltaGas Services.	May 1, 2004 Director of AltaGas Services from March 28, 1994 to April 30, 2004	991,732 Trust Units Nil Trust Options
<i>Allan L. Edgeworth</i> ⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta, Canada Director	President ALE Energy Inc. from January 2005. President and Chief Executive Officer Alliance Pipeline Ltd. from 2001 through 2004. Executive Vice President and Chief Operating Officer Alliance Pipeline 1998 to 2001.	March 2, 2005	3,000 Trust Units 35,000 Trust Options
<i>Denis C. Fonteyne</i> ⁽²⁾⁽³⁾⁽⁵⁾ Calgary, Alberta, Canada Director	Natural gas industry consultant since 1997.	May 1, 2004 Director of AltaGas Services from September 1, 1998 to April 30, 2004	36,300 Trust Units 15,000 Trust Options
<i>Daryl H. Gilbert</i> ⁽²⁾⁽⁴⁾⁽⁵⁾⁽⁸⁾ Calgary, Alberta, Canada Director	Independent businessman from January 2005. Prior thereto President and Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd. (an engineering consulting firm).	May 1, 2004 Director of AltaGas Services from May 4, 2000 to April 30, 2004	900 Trust Units 15,000 Trust Options
<i>Robert B. Hodgins</i> ⁽²⁾⁽⁴⁾⁽⁶⁾ Calgary, Alberta, Canada Director	Independent businessman from November 2004. Chief Financial Officer Pengrowth Energy Trust from 2002 to 2004. Vice President and Treasurer Canadian Pacific Limited 1998 to 2002.	March 2, 2005	2,000 Trust Units 35,000 Trust Options
<i>Myron F. Kanik</i> ⁽²⁾⁽⁵⁾⁽⁶⁾⁽⁷⁾ Calgary, Alberta, Canada Director	President Kanik and Associates Ltd. (an energy industry consulting company).	May 1, 2004 Director of AltaGas Services from June 1, 2001 to April 30, 2004	43,960 Trust Units 15,000 Trust Options
<i>David F. Mackie</i> ⁽²⁾⁽⁵⁾⁽⁶⁾ Houston, Texas, United States Director	Energy industry consultant and venture capital investor.	May 1, 2004 Director of AltaGas Services from January 12, 1995 to April 30, 2004	1,055,216 Trust Units 15,000 Trust Options
<i>M. Neil McCrank, Q.C., P.Eng.</i> Calgary, Alberta, Canada Director ⁽²⁾⁽³⁾⁽⁶⁾	Consultant to government and industry on energy matters from April 2007. Prior thereto, Chairman of the Alberta Energy and Utilities Board from July 1998 until his retirement on March 31, 2007.	December 10, 2007	Nil Trust Units 20,000 Trust Options

(1) References to Trust units in this column includes both Trust units and Exchangeable units beneficially owned, directly or indirectly, or over which control or direction is exercised by each director and officer as at December 31, 2007.

(2) Independent director.

(3) Member of the Environment, Occupational Health and Safety Committee.

(4) Member of the Audit Committee.

(5) Member of the Human Resources and Compensation Committee.

(6) Member of the Governance Committee.

(7) Lead director.

(8) Mr. Gilbert is also a director of Globel Direct, inc. (Globel). Globel was the subject of a cease trade order issued by the Alberta Securities Commission on November 22, 2002 and the British Columbia Securities Commission on November 20, 2002 because Globel had not filed its Annual Financial Statements for its fiscal year ending May 31, 2002 and its Interim Financial Statements for its first quarter ended August 31, 2002 prior to the prescribed filing deadlines. Globel filed the Annual Financial Statements and Interim Financial Statements and the cease trade order was removed by the Commissions on December 20, 2002 and December 23, 2002, respectively. On June 12, 2007, Globel was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the Companies' Creditors Arrangement Act. Such protection expired on December 7, 2007, the Monitor was discharged on December 12, 2007, and a receiver/manager was appointed.

(9) Mr. Cornhill is not considered to be an independent director as he is an executive officer of the General Partner.

Name of Officer, Municipality of Residence and Position with the General Partner⁽²⁾	Principal Occupation During the Past Five Years	Officer Since	Securities Beneficially Owned or Controlled⁽¹⁾
<i>Richard M. Alexander</i> Calgary, Alberta, Canada President and Chief Operating Officer	President and Chief Operating Officer from January 2008. Executive Vice President Chief Operating Officer and Chief Financial Officer January 2007 to January 2008. Senior Vice President Finance and Chief Financial Officer from May 2006 to January 2007. Vice President Finance and Chief Financial Officer Niko Resources Ltd. October 2003 to April 2006. Vice President Investor Relations and Communications of Husky Energy Inc. from July 2001 to September 2003. Treasurer Husky Energy Inc. August 2000 to July 2001.	May 1, 2006	20,468 Trust Units Nil Trust Options
<i>David W. Cornhill</i> Calgary, Alberta, Canada Chairman and Chief Executive Officer	Chairman and Chief Executive Officer from January 2008. Chairman, President and Chief Executive Officer of AltaGas and the General Partner from 2005 to January 2008. In 2004, Chairman and Chief Executive Officer of AltaGas and the General Partner. Chairman and Chief Executive Officer of AltaGas Services from 2003 to 2004. Prior thereto President and Chief Executive Officer of AltaGas Services.	March 26, 2004	991,732 Trust Units Nil Trust Options
<i>Dennis A. Dawson</i> Calgary, Alberta, Canada Vice President, General Counsel and Corporate Secretary	Since 2005, Vice President General Counsel and Corporate Secretary. Vice President General Counsel and Corporate Secretary of AltaGas Ltd. from May 1, 2004. Vice President General Counsel and Corporate Secretary of AltaGas Services since 1998.	March 16, 2005	88,071 Trust Units Nil Trust Options
<i>Deborah S. Stein</i> Calgary, Alberta, Canada Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer from January 2008. Vice President Finance from January 2007 to January 2008. Vice President Controller from October 2005 to January 2007. Vice President Corporate Risk from January to October 2005. Manager Investor Relations TransCanada Pipelines Limited from 2001 to 2005.	January 21, 2008	2,931 Trust Units Nil Trust Options
<i>David R. Wright</i> Executive Vice President Strategy and Corporate Development	Executive Vice President from January 2007. Executive consultant 2005 to January 2007. Executive Vice President General Counsel and Corporate Secretary EPCOR Utilities Inc. from 2001 to 2005. Prior thereto Partner with Borden Ladner Gervais LLP and Howard Mackie.	January 16, 2007	14,059 Trust Units 25,000 Trust Options

(1) References to Trust units in this column includes both Trust units and Exchangeable units beneficially owned, directly or indirectly, or over which control or direction is exercised by each director and officer as at December 31, 2007.

(2) On January 21, 2008, Mr. Cornhill was appointed Chief Executive Officer, Mr. Alexander was appointed President and Chief Operating Officer, Mr. Wright was appointed Executive Vice President Strategy and Corporate Development and Deborah S. Stein was appointed Vice President Finance and Chief Financial Officer.

As at December 31, 2007 the directors and executive officers of the General Partner and AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 3,446,877 of the outstanding Trust units and Exchangeable units, or approximately 6 percent of the outstanding Trust units and Exchangeable units. As at December 31, 2007 certain of the directors and officers also had been granted Trust Options to acquire an aggregate of 240,500 Trust units.

Audit Committee Mandate

See attached Schedule A for the Audit Committee Mandate.

Composition of the Audit Committee

The Committee is currently comprised of Allan L. Edgeworth, Daryl H. Gilbert and Robert B. Hodgins. Robert B. Hodgins is the chair of the Committee. All of the members of the Committee are independent and financially literate as defined under Canadian securities law.

Relevant Education and Experience

Allan L. Edgeworth has been the President of ALE Energy Inc. since January 2005. Mr. Edgeworth was the President and Chief Executive Officer of Alliance Pipeline from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline in 1998 as Executive Vice President and Chief Operating Officer. Prior to that, Mr. Edgeworth spent almost 20 years with Westcoast Energy where he held various positions including Vice President of Pipeline Operations and Senior Vice President of Regulatory Affairs.

Daryl H. Gilbert has been an independent businessman since January 2005. Prior to 2005, Mr. Gilbert had a 26-year career with Gilbert Laustsen Jung Associates Ltd., a reservoir engineering company, most recently as President and Chief Executive Officer for 11 years.

Robert B. Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins was Chief Financial Officer at Pengrowth Energy Trust from 2002 to 2004. Mr. Hodgins was Vice President and Treasurer at Canadian Pacific Limited from 1998 to 2002 and Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998. Mr. Hodgins has an Honours Degree in Business from the Richard Ivey School of Business at the University of Western Ontario and is a Chartered Accountant in Ontario and Alberta.

Pre-Approval Policies and Procedures

As set forth in the Committee's charter, the Committee must pre-approve all non-audit services provided by the external auditor and has direct responsibility for overseeing the work of the external auditor.

External Auditor Service Fees by Category

The fees billed by Ernst & Young LLP (E&Y), the Trust's external auditors, for 2006 and 2007 were as follows:

Category of External Auditor Service Fee	2007	2006
Audit Fees	\$676,719	\$478,969
Audit-Related Fees ⁽¹⁾	\$14,712	\$11,175
Tax Fees ⁽²⁾	\$29,031	\$8,325
All Other Fees ⁽³⁾	\$278,724	\$92,415
TOTAL	\$999,186	\$590,884

Notes:

- (1) Represent the aggregate fees billed by E&Y for assurance and related services that were reasonably related to the performance of the audit or review of the Trust's financial statements and were not reported under "Audit Fees". The nature of the services was for accounting advice.
- (2) Represent the aggregate fees billed by E&Y for professional services for tax compliance, tax advice and tax planning. The nature of the services was tax services and tax planning.
- (3) Represent the aggregate fees billed by E&Y for products and services, other than those reported with respect to the other categories of service fees. The nature of the services was for translation services and non-audit/tax related fees.

UNANIMOUS SHAREHOLDER AGREEMENT

Pursuant to the Unanimous Shareholder Agreement, the General Partner was granted the powers of the directors of AltaGas Ltd. to manage, or supervise the management of, the business and affairs of AltaGas Ltd., including without limitation in respect of the following matters:

- (a) The appointment of the board of directors of AltaGas Ltd., as determined by the Board of Directors in its sole discretion; and
- (b) The appointment, mandates and compensation of the executive officers of AltaGas Ltd.

ALTAGAS LTD.

AltaGas Ltd. is the resultant corporation from the amalgamation of ASI, certain of its subsidiaries and an electing shareholder pursuant to the Arrangement. As a result, AltaGas Ltd. owns, directly or indirectly, all of the assets that ASI owned, directly or indirectly, prior to conversion of the business of ASI to the Trust. AltaGas Ltd. retained certain of the liabilities of ASI, including liabilities relating to corporate and income tax matters.

In accordance with the Administration Agreement, AltaGas Ltd. provides all the management, administrative and operating services to the Trust. At December 31, 2007 AltaGas Ltd. and its subsidiaries employed a total of 564 individuals.

DIRECTORS AND OFFICERS

The names, municipality of residence and position of each of the current executive officers of AltaGas Ltd. are as follows:

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
<i>Gregory A. Aarssen</i> Chatham, Ontario, Canada Vice President Corporate Affairs	Vice President Corporate Affairs from January 2008. Divisional Vice President Energy Management from January 2007 to January 2008. Vice President Retail Services PremStar October 2004 to January 2007. Vice President PremStar Energy Canada Ltd. January 1998 to October 2004.
<i>Richard M. Alexander</i> Calgary, Alberta, Canada President and Chief Operating Officer and Director	President and Chief Operating Officer from January 2008. Executive Vice President Chief Operating Officer and Chief Financial Officer since January 2007 to January 2008. Senior Vice President Finance and Chief Financial Officer from May 2006 to January 2007. Vice President Finance and Chief Financial Officer Niko Resources Ltd. October 2003 to April 2006. Vice President Investor Relations and Communications of Husky Energy Inc. from July 2001 to September 2003. Treasurer Husky Energy Inc. August 2000 to July 2001.
<i>Nancy A. Anderson</i> Calgary, Alberta, Canada Vice President Business Development	Vice President Business Development since June 2005. Divisional Vice President Power Services from 2002 to 2005. Senior Vice President El Paso Merchant Energy Canada from 1999 to 2001.
<i>Jeremy R. Baines</i> Calgary, Alberta, Canada Treasurer	Treasurer since July 2005. Manager Corporate Finance Agrium Inc. from 2002 to 2005. Treasury Manager Agrium Inc. from 1999 to 2002.
<i>James B. Bracken</i> Calgary, Alberta, Canada Senior Vice President Major Projects	Senior Vice President Major Projects from June 2007. Senior Vice President Energy Services and Power March 2006 to June 2007. Senior Vice President Energy Services from June 2005 to March 2006. Divisional Vice President Gas Services from 2004 to 2005. Managing Director Advisory Services for Acres Management Consulting from 2002 to 2004. Principal with PA Consulting Group from 2000 to 2001.
<i>David W. Cornhill</i> Calgary, Alberta, Canada Chairman and Chief Executive Officer and Director	Chairman and Chief Executive Officer from January 2008. Chairman, President and Chief Executive Officer of AltaGas and the General Partner to January 2008. In 2004, Chairman and Chief Executive Officer of AltaGas and the General Partner. Chairman and Chief Executive Officer of AltaGas Services from 2003 to 2004. Prior thereto President and Chief Executive Officer of AltaGas Services.
<i>Dennis A. Dawson</i> Calgary, Alberta, Canada Vice President General Counsel and Corporate Secretary and Director	Vice President General Counsel and Corporate Secretary since 1998.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
<i>Massimiliano Fantuz</i> Chatham, Ontario, Canada Executive Vice President	Executive Vice President from January 2008. Vice President January 2007 to January 2008. Divisional Vice President Gas Services from 2005 to January 2007. President PremStar Energy Canada Limited Partnership from 2004. President PremStar Energy Canada Ltd. from 1998 to 2004.
<i>Michael J. Kilby</i> Chatham, Ontario, Canada Divisional Vice President Gas Services	Divisional Vice President Gas Services from January 2007. Vice President Operations PremStar from October 2004 to January 2007. Vice President Marketing and Operations PremStar Energy Canada Ltd. from February 1998 to October 2004.
<i>Bradley G.H. Mattson</i> Calgary, Alberta, Canada Vice President and Corporate Controller	Vice President and Corporate Controller from January 2008. Prior thereto, Chief Financial Officer, Taylor Gas Liquids Ltd.
<i>Patricia M. Newson</i> Calgary, Alberta, Canada Senior Vice President	President and Chief Executive Officer of Utility Group since July 2005. Senior Vice President since May 2006. Senior Vice President Finance and Chief Financial Officer 1996 to April 2006.
<i>Jeffrey F. Perry</i> Calgary, Alberta, Canada Divisional Vice President Field Gathering and Processing	Divisional Vice President Field Gathering and Processing since January 2007. Divisional Vice President Gathering and Processing Operations from June 2005 to January 2007. Divisional Vice President Field Gathering and Processing from 2003 to June 2005. Area Manager Cochrane Extraction Plant Williams Canada 2001 to 2003.
<i>Marilyn A. Pfaefflin</i> Calgary, Alberta, Canada Divisional Vice President Transmission	Divisional Vice President Transmission since June 2005. Treasurer from 1998 to June 2005.
<i>Deborah S. Stein</i> Calgary, Alberta, Canada Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer from January 2008. Vice President Finance from January 2007 to January 2008. Vice President Controller from October 2005 to January 2007. Vice President Corporate Risk from January to October 2005. Manager Investor Relations TransCanada Pipelines Limited from 2001 to 2005.
<i>Kent E. Stout</i> Calgary, Alberta, Canada Vice President Corporate Resources	Vice President Corporate Resources since 2002. Director Human Resources from 1999 to 2002.
<i>Randy W. Toone</i> Calgary, Alberta, Canada Divisional Vice President Extraction and Transmission	Divisional Vice President Extraction and Transmission since January 2007. Operations Manager Extraction and Transmission from November 2004 to January 2007. Senior Operations Engineer November 2003 to November 2004. Plant Engineer Williams Energy Canada January 2002 to November 2003.
<i>David R. Wright</i> Calgary, Alberta, Canada Executive Vice President Strategy and Corporate Development and Director	Executive Vice President Strategy and Corporate Development from January 2008. Executive Vice President from January 2007 to January 2008. Executive consultant 2005 to January 2007. Executive Vice President General Counsel and Corporate Secretary EPCOR Utilities Inc. from 2001 to 2005. Prior thereto Partner with Borden Ladner Gervais LLP and Howard Mackie.

RISK FACTORS

RISKS RELATING TO THE TRUST AND THE UNITS OF THE TRUST

A security holder should consider carefully the risk factors set out below. In addition, prospective security holders should carefully review and consider all other information contained in this Annual Information Form before making an investment decision and consult their own experts where necessary.

Nature of Trust Units

The Trust units do not represent a traditional investment in the diversified energy services business and should not be viewed by unitholders as shares in AltaGas. The units represent a fractional interest in the Trust. As holders of units, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets are the shares of the General Partner, the units of the Holding Trust, Holding Trust Notes and other investments in securities.

Cash distributions of the Trust are not guaranteed and the price per Trust unit is a function of anticipated distributions, the underlying assets of the Trust and management's ability to effect long-term growth in the value of AltaGas and other entities now or hereafter owned directly or indirectly by the Trust. The market price of the Trust units will be sensitive to a variety of market conditions including, but not limited to, interest rates, electricity prices and natural gas and NGL prices. Changes in market conditions may adversely affect the trading price of the Trust units.

The Trust units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Potential Sales of Additional Trust Units

The Trust may issue additional Trust units in the future to directly or indirectly fund capital expenditure requirements of entities now or hereafter owned directly or indirectly by the Trust, including to finance acquisitions by those entities. Such additional Trust units may be issued without the approval of unitholders. Unitholders will have no pre-emptive rights in connection with such additional issues. The Board of Directors has discretion in connection with the price and the other terms of the issue of such additional Trust units.

Nature of Distributions

Unlike interest payments on an interest-bearing security, cash distributions by income trusts on Trust units (including those of the Trust) are, for Canadian tax purposes, composed of different types of payments (portions of which may be fully or partially taxable or may constitute non-taxable returns of capital). The composition for tax purposes of those cash distributions may change over time, thus affecting the after-tax return to unitholders. Therefore, a unitholder's rate of return over a defined period may not be comparable to the rate of return on a fixed-income security that provides a return on capital over the same period. This is because a unitholder may receive cash distributions that constitute a return of capital (rather than a return on capital) to some extent during the relevant period. Returns on capital are generally taxed as ordinary income or as dividends in the hands of a unitholder while returns of capital are generally non-taxable to a unitholder (but reduce a unitholder's adjusted cost base in the Trust unit for tax purposes). The Trust expects that substantially all of the cash distributions to unitholders will be taxed as ordinary income. See "Declaration of Trust and Description of Units – Distributions". Unitholders are advised to consult their own tax advisors with respect to the implications of the distinction discussed above in their own circumstances.

Variability of Distributions

The Cash Flow of the Trust available for distribution to unitholders is a function of numerous factors, including AltaGas' financial performance, the impact of interest rates, electricity prices, natural gas and NGL prices, debt covenants and obligations, working capital requirements and future capital requirements. Distributions may be reduced or suspended entirely depending on the operations of AltaGas and the performance of its assets.

The market value of the Trust units may deteriorate if the Trust is unable to meet its distribution targets in the future, and that deterioration may be material.

Changes in Legislation

Environmental and applicable operating legislation may be changed in a manner which adversely affects AltaGas through the imposition of restrictions on its business activities or by the introduction of regulations that increase AltaGas' operating costs thereby indirectly affecting the Trust and potentially reducing distributions to unitholders.

Income tax laws relating to the Trust, such as the status of mutual fund trusts, may be changed in a manner which adversely affects unitholders.

Federal Government Changes and Proposed Changes to Taxation of Income Trusts

On October 31, 2006 the Minister of Finance (Canada) ("Finance") announced proposed changes to the taxation of certain publicly-traded trusts and partnerships and their unitholders. These changes (the "SIFT Rules"), were enacted and became law on June 22, 2007. The SIFT Rules apply, in the case of trusts, to a trust that is resident in Canada for purposes of the Tax Act, holds one or more "non-portfolio properties", and the units of which are listed on a stock exchange or other public market (a specified investment flow-through trust, or "SIFT trust"). In the case of a SIFT trust the units of which were already publicly traded on October 31, 2006, which includes the Trust, the SIFT Rules generally will not take effect until January 1, 2011, provided the trust does not exceed "normal growth" before then. On December 15, 2006 Finance issued guidelines with respect to what would be considered "normal growth" for this purpose, which guidelines were effectively incorporated by reference into the Tax Act when the SIFT Rules were enacted. On December 20, 2007 Finance announced proposed technical amendments to the SIFT Rules. The proposed technical amendments, while not enacted, are intended to clarify the SIFT Rules.

Under the SIFT Rules, commencing January 1, 2011, the Trust will become subject to tax on its income from non-portfolio properties and taxable capital gains from dispositions of non-portfolio properties, that is paid or payable to Unitholders, at a rate equal to the then prevailing corporate income tax rate (currently set at 16.5 percent for 2011 and 15 percent for 2012 and subsequent years) plus an additional amount in lieu of provincial tax (while currently set at 13 percent, a proposal in the federal budget on February 26, 2008 would base the rate on the general corporate income tax rate of each province in which the Trust has a permanent establishment). Distributions of such income to Unitholders would be treated as dividends paid by a taxable Canadian corporation. The trust units of Holding Trust and the Holding Trust Notes constitute "non-portfolio properties" of the Trust under the SIFT Rules, with the result that virtually all of the Trust's income would be subject to the new tax, and distributions of such income by the Trust to its Unitholders would be treated as dividends paid by a taxable Canadian corporation. Returns of capital by the Trust to its Unitholders would not be affected by the SIFT Rules and would continue to be taxed in the same manner as currently.

It is not expected that the Trust will become subject to the SIFT Rules until 2011. However, when the SIFT Rules commence to apply to the Trust, such rules are expected to result in adverse tax consequences to the Trust and certain Unitholders (in particular, Unitholders that are tax exempt or non-residents of Canada) and may impact cash distributions from the Trust.

In light of the foregoing, the SIFT Rules may reduce the value of the Units, which would be expected to increase the cost to the Trust of raising capital in the public capital markets. There can be no assurance that the Trust will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the SIFT Rules.

As noted above, the Trust could become subject to the SIFT Rules before 2011 if it experiences growth, other than "normal growth", before that time. Under the "normal growth" guidelines, the Trust will be considered to have experienced only "normal growth" if its issuances of new equity (which for this purpose includes Trust units and debt that is convertible into Trust units, but does not include non-convertible debt) do not exceed, for each of the intervening periods set forth below, a safe harbour measured by reference to the Trust's market capitalization as of the end of trading on October 31, 2006 (measured solely by the value of the Trust's issued and outstanding publicly-traded Trust units as of that date). The Trust's market capitalization as of October 31, 2006 was approximately \$1.5 billion. The intervening periods and their respective safe harbour amounts are as follows:

- (a) November 1, 2006 to December 31, 2007 – 40 percent of the Trust's market capitalization as of October 31, 2006;
- (b) January 1, 2008 to December 31, 2008 – 20 percent of the Trust's market capitalization as of October 31, 2006;
- (c) January 1, 2009 to December 31, 2009 – 20 percent of the Trust's market capitalization as of October 31, 2006;

- (d) January 1, 2010 to December 31, 2010 – 20 percent of the Trust's market capitalization as of October 31, 2006.

The "normal growth" guidelines provide that these annual safe harbour amounts are cumulative, and that replacing debt that was outstanding as of October 31, 2006 with new equity, whether through a debenture conversion or otherwise, will not be considered growth for these purposes. In addition, an issuance of new equity will not be considered growth to the extent that the issuance is made in satisfaction of the exercise by another person of a right in place on October 31, 2006 to exchange an interest in a partnership, or a share of a corporation, for Trust units.

While these guidelines are such that it is unlikely they would affect the Trust's ability to raise the capital required to maintain and grow its existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and the Trust's ability to undertake more significant acquisitions.

Loss of Mutual Fund Trust Status

The General Partner intends that the Trust will continue to qualify as a mutual fund trust (and thus also as a registered investment) for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements to maintain its mutual fund trust status. See "Changes in Legislation" above. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and unitholders. Some of the significant consequences of losing mutual fund trust status are listed below.

- (a) If the Trust were to cease to be a mutual fund trust, it may, as a consequence of ceasing to be a mutual fund trust, also cease to be a registered investment. In that event, units would cease to be qualified investments for Exempt Plans effective January 1st of the second calendar year following the year in which the Trust ceases to be a registered investment. If, at the end of any month, an Exempt Plan holds units that are not qualified investments, the plan must pay a tax equal to 1 percent of the fair market value of the units at the time the units were acquired by the Exempt Plan. A registered retirement savings plan or registered retirement income fund holding units that are not qualified investments would be subject to taxation on income attributable to the units, including the full amount of any capital gain from a disposition of such units. If a registered education savings plan holds units that are not qualified investments, it may have its registration revoked by the Canada Revenue Agency.
- (b) Units held by non-resident unitholders would immediately become taxable Canadian property. Non-resident unitholders would be subject to Canadian income tax and reporting requirements on any gains realized on a disposition of units held by them.
- (c) The Trust would be taxed on certain types of income distributed to unitholders (apart from under the SIFT Rules). Payment of this tax may have adverse consequences for some unitholders, particularly unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- (d) The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- (e) The Trust would no longer be exempt from the application of the alternative minimum tax provisions of the Tax Act.

In addition, the Trust may take certain measures in the future to the extent it believes necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain unitholders, particularly non-residents. See "Risks Associated With the Level of Foreign Ownership" below.

Risks Associated With the Level of Foreign Ownership

The Declaration of Trust contains a number of provisions designed to protect the status of the Trust as a "mutual fund trust" under the Tax Act which, inter alia, requires that a mutual fund trust cannot be established or maintained primarily for the benefit of non-residents. There is no indication that the mutual fund trust status of the Trust currently is in jeopardy. If, in the future, the General Partner determines that any such risk exists, it is entitled to take a number of actions under the Declaration of Trust, including requiring unitholders that it believes are non-residents to sell their Trust units, which actions may have an adverse effect on the market price of the Trust units. In addition, there can be no assurances that the Tax Act will not be amended in the future in a manner that would have a material adverse impact on the mutual fund trust status of the Trust.

Distribution of Holding Trust Notes or Other Securities on Redemption or Termination of the Trust

It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. Holding Trust Notes which may be received as a result of a redemption of units will not be listed on any stock exchange and no market for Holding Trust Notes is expected to develop. In addition, there may be resale restrictions imposed by applicable law upon the recipients of Holding Trust Notes pursuant to the redemption right. The Holding Trust Notes will not be qualified investments for Exempt Plans. On termination of the Trust, the Trustee may distribute securities directly to unitholders, subject to obtaining all of the necessary regulatory approvals. The Holding Trust Notes will not be guaranteed by any other party, and the provisions of the Holding Trust Note Indenture governing events of default and the remedies available thereunder will not provide protection to the holders of Holding Trust Notes which would be comparable to the provisions generally found in debt securities issued to the public;

Debt Service

The Trust or its affiliates may, from time to time, finance a significant portion of their operations through debt. Amounts paid in respect of interest and principal on debt incurred by these entities may impair the ability to satisfy any obligations under its indebtedness held by the Trust or indirectly by the Trust. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Ultimately, this may result in lower levels of Cash Flow of the Trust and could reduce distributions to unitholders.

Loans to the Trust or its affiliates are subject to customary covenants and financial tests which may in certain circumstances restrict the Trust's ability to make distributions to unitholders or AltaGas' ability to make distributions to AltaGas LP #2 and ultimately to unitholders.

Structural and Contractual Subordination

In the event of a bankruptcy, liquidation or reorganization of AltaGas LP #1, AltaGas or AltaGas Operating Partnership, holders of their respective indebtedness and trade payables will generally be entitled to payment of their claims from the assets of AltaGas or AltaGas Operating Partnership, as applicable, before any assets are made available for distribution to the Trust. The Trust units are therefore effectively junior to indebtedness and most other liabilities (including trade payables) of AltaGas, AltaGas LP #1 and AltaGas Operating Partnership. Neither AltaGas nor AltaGas Operating Partnership is limited in its ability (except pursuant to restrictive covenants contained in debt agreements) to incur secured or unsecured indebtedness.

AltaGas distributes a substantial portion of its cash flow to AltaGas LP #2 pursuant to an interest bearing loan agreement. Payments by AltaGas under this loan agreement are expressly subordinated to the prior payment in full of all indebtedness of AltaGas to third parties. Upon a default under certain indebtedness, AltaGas may be prevented from distributing cash to AltaGas LP #2 thereby ultimately reducing cash available for distribution to unitholders.

Dependence on Operating Entities

The Trust is entirely dependent upon the success of the operations of affiliates. Accordingly, the distributions to the unitholders will be dependent on the ability of these entities to generate cash flow.

Taxation of Corporate Entities

Income fund structures often involve significant amounts of inter-entity debt, generating substantial interest expense, which serves to reduce earnings and therefore income tax payable. The Board of Directors expects this to be the case in respect of AltaGas Ltd. and its interest expense on its subordinated debt. There can be no assurance that taxation authorities will not seek to challenge the amount of interest expense deducted. If such a challenge were to succeed against AltaGas Ltd. it could have a material adverse affect on the Cash Flow of the Trust available for distribution to unitholders.

Unitholder Limited Liability

The Declaration of Trust provides that no unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Declaration of Trust, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a unitholder resulting from or arising out of such unitholder not having such limited liability. There is no assurance that at the relevant time the Trust will have sufficient assets to be able to satisfy such indemnity.

The Declaration of Trust provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that obligations under those instruments will not be binding upon unitholders personally. Personal liability may however arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust will be conducted, upon the advice of counsel to the Trust, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the unitholders for claims against the Trust, including by obtaining appropriate insurance, where available and to the extent commercially feasible.

On July 1, 2004, the *Income Trusts Liability Act* (Alberta) came into force, which provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the Trustee that arises after the particular provision of such legislation comes into force.

Deductibility of Expenses

Although the General Partner is of the view that all expenses to be claimed by the Trust, Holding Trust, AltaGas LP #1 and AltaGas LP #2 will be reasonable and deductible, there can be no assurance that the Canada Revenue Agency will agree. If the Canada Revenue Agency successfully challenges the deductibility of any such expenses, the return to unitholders may be adversely affected.

Potential Conflicts of Interest

Circumstances may arise where directors and officers of AltaGas and the General Partner are directors or officers of other entities that are in competition to the interests of AltaGas and the Trust. The General Partner owes a fiduciary duty to AltaGas and the Trust. While the General Partner has agreed to indemnify the Trust in certain circumstances, the General Partner may not have sufficient assets to honour such indemnification.

RISKS INHERENT IN THE TRUST'S OPERATING ENTITIES

The following are the primary risks associated with the business and affairs of the Trust's operating affiliates and should be considered carefully in light of the fact that the Trust will depend entirely on the operations and assets of these entities for its cash flow, and thereby its ability to pay distributions to unitholders. These risks are applicable to AltaGas' current operations and AltaGas' expected future operations.

Operating Risk

As the Trust continues to grow and diversify its energy infrastructure business, the risk profile of the Trust may change. Operating entities may enter into or expand business segments where there is greater economic exposure and more "at risk" capital. The Trust's expectation of higher returns from these businesses justifies the level of risk. In addition the Trust enters into these businesses on the basis that these risks can be actively managed.

Current operations are subject to the risks normally associated with the operation and development of natural gas and power facilities, including mechanical failure, physical degradation, operator error, manufacturer defects, sabotage, terrorism, failure of supply, catastrophic events and natural disasters. The occurrence or continuation of these events could increase AltaGas' costs and reduce its ability to process or transport natural gas or deliver power.

The Trust believes that operational risk is best managed by maintaining control over the timing of capital expenditures, operational decisions and costs by becoming the operator of the facilities in which it invests. At the end of 2007 AltaGas operated 71 of its 74 field gathering and processing facilities, all of its transmission facilities, EEEP and the gas-fired peaking units. AltaGas does not operate the power plant from which power is generated under the PPAs. Failure by the operators of these facilities to operate at the cost or in the manner projected by AltaGas could negatively affect the Trust's results.

On January 10, 2008 the Trust completed the acquisition of Taylor and as a consequence became operator of the Joffre Extraction Plant, the Younger Extraction Plant, the Harmattan Complex, the RET Complex, EDP and JFP.

Facility Throughput

AltaGas' field gathering and processing, extraction and transmission facilities process or transport natural gas from the WCSB. Throughput at these facilities is dependent on a number of factors, including the level of exploration and development activity within the WCSB, the long-term supply and demand dynamics for natural gas and the regulatory environment for natural gas market participants. These factors may result in AltaGas being unable to maintain

throughput at its facilities. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas throughput and from rising operating costs.

At all of its field gathering and processing facilities, AltaGas actively pursues opportunities to maintain or increase throughput. AltaGas' contract provisions mitigate the impact of volume declines, generate additional volumes for gathering and processing at its facilities, encourage expansion into areas where AltaGas' facilities are located and allow AltaGas to recover its invested capital in a relatively short period of time. The majority of AltaGas' field processing facilities is skid-mounted and can be moved to areas with favourable production potential should a particular area's production decline significantly.

Market Risk

AltaGas is exposed to market risks resulting from movements in commodity prices and interest rates. AltaGas manages its exposure to these risks through the use of various physical and financial instruments.

AltaGas' Commodity Risk Management Policy details the parameters used to measure, monitor and report commodity price risks. It also includes risk management guidelines and objectives, risk tolerance and approved products. This policy prohibits the use of physical and financial instruments for speculative purposes.

Composition Risk

The extraction business is influenced by the composition of natural gas produced in the WCSB and processed at AltaGas' facilities. The composition of the gas stream has the potential to vary over time due to factors such as the level of processing done at plants upstream of AltaGas' facilities and the composition of the natural gas produced from reservoirs upstream of AltaGas' facilities.

Electricity Prices

AltaGas' revenue from sales related to PPAs and Alberta peaking plant generation are subject to Alberta electricity market factors such as fluctuating supply and demand, which may be affected by weather, customer usage, economic activity and growth. AltaGas reduces its exposure to floating electricity prices by locking in margins with financial instruments out as far as 36 months and signing fixed-price sales arrangements with end-use customers for terms of up to 8 years.

Interest Rates

The Trust is exposed to interest rate fluctuations on variable rate debt. The Trust monitors its level of fixed to variable rate debt and from time to time enters into interest rate swaps. The Trust's target is to have approximately 70 to 75 percent of its debt at fixed interest rates. At December 31, 2007 the Trust had fixed interest rates on \$25 million or 100 percent of its floating rate debt through interest rate swaps. At year-end, \$220.7 million or 100 percent of the Trust's total debt, including its medium-term notes, capital lease and swaps, was at fixed interest rates. AltaGas anticipates returning to target levels for fixed rate debt in conjunction with the financing of the Taylor acquisition.

Regulatory

The Trust's businesses are subject to regulation in the jurisdictions in which they carry on business. Pipelines and facilities can be subject to common carrier and common processor applications and to rate setting by the regulatory authorities in the event an agreement on fees or tariffs cannot be reached with producers. To the extent that producers believe processing fees or tariffs respecting pipelines and facilities are too high, they may seek relief through regulator intervention.

Credit Risk

The Trust is exposed to credit-related losses in the event that counterparties to contracts fail to fulfill their present or future financial obligations to AltaGas. AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses which allow for AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas provides an allowance for doubtful accounts in the normal course of its business.

AltaGas has credit risk relating to numerous industrial, commercial and institutional counterparties. AltaGas is satisfied that the counterparties are sufficiently well diversified such that there is no excessive concentration of risk associated with any particular industry or counterparty.

Collateral

AltaGas is able to obtain unsecured credit limits from its counterparties in order to lock in baseload electricity margins and also to procure natural gas supply and services for its energy services business. If counterparties' credit exposure to AltaGas exceeds the unsecured credit limits granted, AltaGas may have to provide collateral in the form of letters of credit. AltaGas mitigates this risk through negotiation of contractual terms with counterparties related to unsecured credit, and diversification of electricity sales and natural gas purchases among a number of counterparties. Through accepted industry practices, AltaGas performs sensitivity analysis to ensure the Trust has sufficient bank lines of credit available to withstand commodity price movements that may require AltaGas to provide counterparties with letters of credit.

REP Agreements

If AltaGas becomes insolvent or is in material default under the terms of the Rep Agreements for an extended period, effective ownership of the natural gas processing plant within the Harmattan Complex can be claimed by the original Harmattan Complex owners for a nominal fee. Accordingly, under these circumstances, AltaGas could lose its investment in the natural gas processing plant, excluding the Caroline Pipeline and various ancillary facilities that are owned 100 percent by AltaGas. In addition, if the Rep Agreements are terminated by the producers prior to June 1, 2009 due to a default by AltaGas, AltaGas will retain certain environmental liabilities which have accrued up to the date of termination.

Harmattan Complex - Environment

Management has identified environmental issues associated with the prior activities of the Harmattan Complex. There are indications of significant groundwater and soil contamination resulting from the Harmattan Complex's prior activities. There is a risk that the costs of addressing these environmental issues could be significant. An environmental allocation agreement is in place with the former operator which allocates the liability. This agreement significantly reduces the soil contamination liability and eliminates the groundwater contamination liability to AltaGas.

Labour Relations

The operations and maintenance staff at the Younger Extraction Plant are members of the Communications, Energy and Paperworkers' Union of Canada. Labour disruptions could restrict the ability of the plant to process natural gas and produce NGLs and therefore affect AltaGas' cash flow, net income and cash available for distribution.

Aboriginal Land Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of the lands in western Canada. Such claims, if successful, could have a significant adverse effect on natural gas production in Alberta and British Columbia which could have a materially adverse effect on the volume of natural gas processed at AltaGas' facilities or on development of new facilities for gathering and processing, power generation or extraction and transmission.

Crown Duty to Consult First Nations

The federal and provincial governments in Canada have a duty to consult and, where appropriate, accommodate aboriginal people where the interests of the aboriginal peoples may be affected by a Crown action or decision. Accordingly, the Crown's duty may result in regulatory approvals being delayed or not being obtained.

NGL Inquiry

The ERCB is currently holding an inquiry into matters related to NGL extraction from the common natural gas stream transported through pipeline transmission systems or processed by facilities that are regulated by the ERCB. The ERCB could propose a new extraction rights allocation methodology, which could alter future natural gas supply contracting to straddle plants. The inquiry could also result in new policies for development of new extraction facilities.

Development

The development and future operation of power generation facilities can be affected adversely by changes in government policy and regulation, environmental concerns, increases in capital costs, increases in interest rates and competition in the industry. In the event that any one of these factors emerges, the actual results may vary materially from the projections of power production, future revenue and earnings.

The development of AltaGas' power projects and their future operations are subject to changes in the policies and laws of both the federal and provincial governments, including regulations relating to environmental policies and conflicts of interest with other parties and other related matters beyond the direct control of AltaGas. AltaGas' future power generation operations are subject to government regulation by federal and provincial agencies.

Weather and Long Term Wind or Hydrology Data

AltaGas' run-of-river power projects once built may be subject to significant variations in precipitation and amount of snow pack in the watershed which would then affect the stream flow necessary for power generation. AltaGas relies on hydrological studies and data to confirm sufficient water flows are available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical water availability will remain unchanged or that no material hydrologic event will impact the hydrologic conditions that exist within the watersheds. Annual deviations from the long-term average can be significant. This risk is mitigated by the relatively diverse geographic locations of AltaGas' portfolio of renewable energy projects.

AltaGas' wind power projects once built may be subject to significant variations wind which would then affect the wind necessary for power generation. AltaGas relies on wind studies and data to confirm sufficient wind flows are available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical wind patterns will remain unchanged. Annual deviations from the long-term average can be significant.

ENVIRONMENTAL REGULATION

The natural gas gathering and processing industry and the power generation industry are subject to environmental regulation pursuant to local, provincial, territorial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. Due to the highly toxic and corrosive nature of sour gas, numerous extra regulatory precautions are applied to sour gas wells, processing facilities and pipelines. Environmental legislation can affect the operation of facilities and limit the extent to which facility expansion is permitted. In addition, provincial, territorial and federal legislation requires that facility sites and pipelines be abandoned and reclaimed to the satisfaction of provincial authorities and local landowners. A breach of such legislation may result in the imposition of fines, the issuance of clean-up orders or the shutting down of facilities and pipelines.

AltaGas takes its responsibility to protect the environment in which it operates very seriously. Its mandate is to fully comply with all environmental laws and regulations and to immediately and efficiently deal with any environmental incidences.

With respect to the Kyoto Protocol on Climate Change, the federal government has stated it will not implement the Kyoto Protocol. Instead, on April 26, 2007, the federal government proposed its alternative plan for addressing greenhouse gas emissions. Under this plan, facilities with greenhouse gas emissions exceeding a threshold level will be required to reduce their net greenhouse gas emissions intensity by 18 percent (relative to 2006 levels) by 2010. The threshold level of greenhouse gas emissions has yet to be determined. Compliance options include making operating improvements, participating in domestic emissions trading, buying a domestic offset to apply against the emission total, buying a Certified Emissions Reductions credit through the Kyoto Protocol's Clean Development Mechanism up to a prescribed maximum amount or contributing to an independent, third-party-administered fund that will invest in technology to reduce greenhouse gas emissions in Canada. However, the Kyoto Protocol Implementation Act was passed by the House of Commons and Senate and became effective June 22, 2007. This act requires the federal government to issue regulations to meet the greenhouse gas emission reduction targets set forth in the Kyoto Protocol. The federal government has indicated that it will proceed with its alternative plan. Since the federal government has proposed implementing its plan by enacting a regulation under the Canadian Environmental Protection Act, parliamentary approval for its plan will not be required. Until the relevant legislation and regulations are enacted, AltaGas is not in a position to accurately determine the impact of any federal requirement to reduce greenhouse gas emission levels on its financial position.

On March 8, 2007 the Alberta government introduced the Climate and Emissions Management Amendment Act and the Specified Gas Emitters Regulation. The act came into force April 20, 2007 and the Specified Gas Emitters Regulation took effect July 1, 2007. The regulation applies to large emitter facilities producing a minimum of 100,000 tonnes of annual greenhouse gas emissions. Large emitters with 8 or more years of commercial operation must achieve annual emissions intensity reductions of 12 percent relative to a baseline emissions intensity established for the facility December 31, 2007. Annual emissions intensity reduction targets are phased in for newer facilities. Compliance options include making operating improvements, buying an Alberta-based offset to apply against the emission total or contributing to the Alberta government's new Climate Change and Emissions Management Fund that will invest in technology to reduce greenhouse gas emissions in the province. Owners of facilities which do not achieve the necessary reduction through operating improvements of offsets must pay \$15 per tonne above the target for reduced emissions to the Climate Change and Emissions Management Fund or they may be assessed with significant one-time and ongoing daily penalties.

AltaGas has completed an assessment program of its larger field gathering and processing facilities to quantify the current levels of greenhouse gas emissions. Other than the Harmattan Complex, none of AltaGas' field gathering and

processing facilities is large emitters subject to the Alberta regulation. The Harmattan Complex falls within the scope of the legislation as its greenhouse emissions are slightly above 100,000 tonnes per year. Management's initial calculations for emission intensity for 2007 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty. The Sundance B Plant is a large emitter and TransAlta, as the facility owner, must ensure that facility complies with the Alberta regulation. The Sundance B PPAs require TransAlta to take all reasonable steps as agreed to by ASTC, and at the cost of ASTC, to minimize any decrease in revenues or increase in the fixed or variable costs resulting from a Change in Law as that term is defined in the PPAs. AltaGas' share of the cost of compliance in 2007 was approximately \$2.0 million.

In its April 26, 2007 announcement, the federal government also proposed a national cap on air pollutants including nitrogen oxides, sulphur oxides, volatiles organic compounds and particulate matter. Sector specific fixed emission caps will also apply to other air pollutants including benzene from natural gas production and processing and refineries, and mercury from electricity generation. The proposal suggests the setting of sectoral emission caps for each of the pollutants to be regulated. The process of setting of these caps and the caps themselves are yet to be determined. Proposed national caps are to be effective as of 2012 to 2015 and include a 40 percent reduction in nitrogen oxide emissions, a 55 percent reduction in sulphur oxide emissions, a 45 percent reduction in volatile organic compounds and a 20 percent reduction in particulate matter (all relative to 2006 emissions levels). Proposed compliance options include making operating improvements or participating in a domestic cap-and-trade program for nitrogen oxides and sulphur oxides. Until the relevant legislation and regulations are enacted, AltaGas is not in a position to accurately determine the impact of any federal requirement to reduce pollutant emissions levels on its financial position.

On February 6, 2006 the Alberta government passed a regulation under the Alberta Environmental Protection and Enhancement Act related to control of mercury emissions from coal-fired power plants. Holders of approvals to operate a coal-fired power plant were required to submit a proposal in accordance with the regulation for a mercury emissions control program at their coal-fired plant prior to April 1, 2007.

TransAlta submitted a mercury emission control program for the Sundance generating station to Alberta Environment on March 29, 2007. The proposal to control mercury emissions suggested that further testing was required before selecting a technology choice. ASTC has been working with TransAlta since 2005 to identify a mercury reduction technology that will reduce mercury emissions by a minimum of 70 percent before January 1, 2011. AltaGas expects that TransAlta will have the appropriate technology choice in place in order to meet their regulatory compliance obligations.

DISTRIBUTIONS

The Trust and AltaGas LP #1 pay cash distributions on or about the 15th day of each month, or if that date is not a business day then the following business day, to unitholders of record on the 25th day of the previous month, or if that day is not a business day the following business day.

Distribution levels are reviewed periodically by the Board of Directors, giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. The Trust targets to pay substantially all of its ongoing sustainable distributable cash through regular monthly distributions made to unitholders.

The Trust's distributions may be limited by its debt covenants under the \$75,000,000 Extendible Revolving Term Credit Facility Credit Agreement and the \$300,000,000 Extendible Revolving Term Credit Facility Credit Agreement, which was increased in January 2008 to \$375,000,000 (see "Material Contracts"), if a default or event of default exists or would be reasonably expected to exist upon or as a result of making such distribution, or if such distribution would cause the aggregate distributions made during the 12-month period ending on the date of such distribution to exceed the cumulative distributable cash for such period.

In addition, the Declaration of Trust provides that, if necessary, on December 31 of each year, the Trust will distribute an additional amount such that the Trust will not be liable for ordinary income taxes for such year. For income tax purposes, 70 percent of the cash distributions declared in 2007 will be taxed as interest income, 1 percent as capital gains and dividend income and the remaining 29 percent classified as return of capital.

The following table summarizes the monthly cash distributions of the Trust during 2005, 2006 and 2007. On November 17, 2005 all unitholders received a special distribution of one share of Utility Group for every 13.9592 Trust units held on November 14, 2005, for additional value of \$0.54 per unit. On September 17, 2007 all unitholders received a special distribution of one share of Utility Group for every 100 Trust units held on August 27, 2007, for additional value of \$0.076 per unit.

Record Date	Payment Date	Distribution per Unit
January 25, 2007	February 15, 2007	\$0.170
February 26, 2007	March 15, 2007	\$0.170
March 26, 2007	April 16, 2007	\$0.170
April 25, 2007	May 15, 2007	\$0.170
May 25, 2007	June 15, 2007	\$0.170
June 25, 2007	July 16, 2007	\$0.170
July 25, 2007	August 15, 2007	\$0.170
August 27, 2007 ⁽¹⁾	September 17, 2007	\$0.175
September 25, 2007	October 15, 2007	\$0.175
October 25, 2007	November 15, 2007	\$0.175
November 26, 2007	December 17, 2007	\$0.175
December 27, 2007	January 15, 2008	\$0.175
Total 2007 Cash Distributions Declared		\$2.065
January 25, 2006	February 15, 2006	\$0.160
February 24, 2006	March 15, 2006	\$0.160
March 27, 2006	April 17, 2006	\$0.165
April 25, 2006	May 15, 2006	\$0.165
May 25, 2006	June 15, 2006	\$0.165
June 26, 2006	July 17, 2006	\$0.165
July 25, 2006	August 15, 2006	\$0.165
August 25, 2006	September 15, 2006	\$0.170
September 25, 2006	October 16, 2006	\$0.170
October 25, 2006	November 15, 2006	\$0.170
November 27, 2006	December 15, 2006	\$0.170
December 22, 2006	January 15, 2007	\$0.170
Total 2006 Cash Distributions Declared		\$1.995
January 25, 2005	February 15, 2005	\$0.150
February 25, 2005	March 15, 2005	\$0.150
March 28, 2005	April 15, 2005	\$0.150
April 25, 2005	May 16, 2005	\$0.150
May 25, 2005	June 15, 2005	\$0.150
June 27, 2005	July 15, 2005	\$0.150
July 25, 2005	August 15, 2005	\$0.150
August 25, 2005	September 15, 2005	\$0.160
September 26, 2005	October 17, 2005	\$0.160
October 25, 2005	November 15, 2005	\$0.160
November 25, 2005 ⁽¹⁾	December 15, 2005	\$0.160
December 23, 2005	January 16, 2006	\$0.160
Total 2005 Cash Distributions Declared		\$1.850

(1) Distributions paid in November 2005 do not include \$0.54 per unit paid to unitholders in the form of shares of Utility Group as a result of the spin-out of the Natural Gas Distribution business. Distributions paid in September 2007 do not include \$0.076 per unit paid to unitholders in the form of shares of Utility Group as a special distribution.

DISTRIBUTION REINVESTMENT PLAN

The Trust has adopted a Premium DistributionTM, Distribution Reinvestment and Optional Unit Purchase Plan for holders of Trust units and holders of Exchangeable units.

The Premium DistributionTM, Distribution Reinvestment and Optional Unit Purchase Plan, as may be amended from time to time, provides eligible holders of Trust units and Exchangeable units with the opportunity to reinvest the cash distributions paid by the Trust or AltaGas LP #1 on their units towards the purchase of new Trust units at a 5 percent discount to the Average Market Price of the Trust units, as defined below, on the applicable distribution payment date (the distribution reinvestment component of the Plan) or to elect to exchange such Trust units for a cash payment equal to 102 percent of such distributions on such date (the premium distribution component of the Plan). The Trust unitholder Plan also provides Trust unitholders who are enrolled in either the distribution reinvestment component or the premium distribution component of the Plan with the opportunity to purchase new Trust units at the Average Market Price (with

no discount) on the applicable distribution payment date (the optional cash payment component of the Plan). Each of the components of the Plan is subject to prorating and other limitations on availability of new Trust units in certain events.

The "Average Market Price", in respect of a particular distribution payment date, refers to the arithmetic average (calculated to four decimal places) of the daily volume weighted average trading prices of Trust units on the TSX for the trading days on which at least one board lot of Trust units is traded during the period beginning on the later of the 21st business day preceding a distribution payment date and the second business day following the record date applicable to such distribution payment date and ending on the second business day preceding such distribution payment date. Such trading prices will be appropriately adjusted for certain capital changes (including Trust unit subdivisions, Trust unit consolidations, certain rights offerings and certain distributions).

No brokerage commissions will be payable in connection with the purchase of Trust units under the distribution reinvestment component of the plan or optional unit purchase component of the plan and all administrative costs under the Plan are borne by the Trust. Proceeds received by the Trust upon the issuance of additional Trust units under the Distribution Reinvestment Plan will be used by AltaGas for future acquisitions, capital improvements and working capital. Unitholders resident outside of Canada are not entitled to participate in the Plan. Upon ceasing to be a resident of Canada, unitholders will be required to terminate their participation in the Plan.

On August 1, 2007 the Trust announced that it had suspended the Premium component of the Distribution Reinvestment Plan effective with the August 15, 2007 distribution payment. The regular component of the Distribution Reinvestment Plan remained in effect.

MARKET FOR SECURITIES

The following chart provides the reported high and low trading prices and volume of Trust units traded by month from January to December 2007 as reported by the TSX:

Month	High	Low	Volume
January	\$26.15	\$25.22	2,068,426
February	\$27.30	\$25.65	1,924,731
March	\$26.95	\$24.15	2,925,952
April	\$27.39	\$24.07	2,070,483
May	\$27.40	\$25.90	2,340,742
June	\$27.00	\$24.99	3,388,669
July	\$28.75	\$25.38	2,694,048
August	\$28.49	\$26.00	2,186,613
September	\$28.25	\$26.12	2,008,269
October	\$27.32	\$25.40	3,357,251
November	\$26.88	\$24.70	3,060,105
December	\$26.50	\$24.74	3,031,024

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table summarizes selected financial information for the last three financial years:

Year ended and as at December 31 <i>(\$ millions unless otherwise indicated)</i>	2007	2006	2005
Revenue			
Field Gathering and Processing	135.1	139.1	131.8
Extraction and Transmission	142.9	149.1	181.3
Power Generation	182.5	199.4	189.2
Energy Services	1,022.5	948.9	1,080.2
Natural Gas Distribution	n/a	n/a	113.4
Corporate	6.2	4.4	10.9
Intersegment Eliminations	(60.8)	(78.3)	(204.5)
	1,428.4	1,362.6	1,502.3
Net revenue			
Field Gathering and Processing	127.4	129.7	120.1
Extraction and Transmission	67.4	63.2	58.0
Power Generation	104.2	99.6	57.8
Energy Services	20.9	24.7	23.5
Natural Gas Distribution	n/a	n/a	29.0
Corporate	6.2	4.4	10.9
Intersegment Elimination	(2.1)	(2.7)	(2.4)
	324.0	318.9	296.9
EBITDA	173.7	173.1	155.5
- per unit (basic)	\$3.03	\$3.12	\$2.88
Net income	108.8	114.5	90.3
- per unit (basic)	\$1.90	\$2.06	\$1.67
Cash from operations	183.3	146.9	112.3
- per unit (basic)	\$3.19	\$2.65	\$2.08
Funds from operations	162.9	161.7	129.0
- per unit (basic)	\$2.84	\$2.91	\$2.39
Total assets	1,199.8	1,109.6	1,068.3
Total debt	220.7	265.5	269.0

CREDIT AND STABILITY RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity and willingness of a company to meet its financial commitment on an obligation in accordance with the terms of an obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an income trust's distribution stream when compared to other rated Canadian income trusts.

S&P and DBRS are rating agencies that provide credit ratings. These rating agencies' ratings for debt instruments range from a high of AAA to a low of D and for stability ratings range from a high of SR-1 (S&P) / STA-1 (DBRS) to a low of SR-7 (S&P) / STA-7 (DBRS). S&P also assigns a corporate rating which ranges from a high of AAA to a low of D.

On December 19, 2006 DBRS upgraded the trend on rating for the medium-term notes issued by the Trust to Positive from Stable. On January 17, 2007, DBRS rated the medium-term notes issued by the Trust at BBB (low) with a Positive trend. On November 12, 2007, DBRS placed the medium-term notes and the Trust's stability rating "Under Review with Developing Implications" following the announcement that AltaGas had agreed to acquire all of the outstanding units of Taylor. This removed the positive trend placed on the medium term notes' rating on December 19, 2006. On January

10, 2008, following the closing of the acquisition of Taylor, DBRS confirmed the medium-term notes and stability ratings at BBB (low), with a Stable trend, and STA-3 (middle), respectively. This removed the ratings from "Under Review with Developing Implications".

On January 12, 2007 S&P affirmed its BBB- rating with a stable outlook on AltaGas corporate credit and senior unsecured debt. S&P rates the Trust's senior unsecured debt at BBB- and AltaGas long-term corporate credit at BBB-. The Trust has a stability rating of STA-3 (middle) from DBRS.

On December 20, 2007 S&P affirmed its BBB- rating with a stable outlook on AltaGas corporate credit and senior unsecured debt. S&P rates the Trust's senior unsecured debt at BBB- and AltaGas long-term corporate credit at BBB-. The Trust has a stability rating of SR-3 from S&P.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. "High" or "low" grades are used to indicate the relative standing within a particular rating category. A stability rating of STA-3 is considered to have good stability and sustainability of distributions per unit. The stability rating is further separated into high, middle and low to indicate where within the ratings category the trust falls. Seven areas are reviewed and assigned a ranking of superior, moderate or weak in determining the overall stability rating. The areas reviewed are operating and industry characteristics, asset quality, financial flexibility, diversification, size and market position, sponsorship and governance, and growth.

According to the S&P rating system, an obligor rated BBB has adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. A stability rating of SR-3 indicates that the Trust has a high level of distributable cash flow generation stability relative to other income funds in the Canadian marketplace.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Except as set forth above, neither DBRS nor S&P has announced that it is reviewing or intends to revise or withdraw the ratings on the Trust.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but which are still material and are still in effect, are the following:

- Declaration of Trust. See "Declaration of Trust and Description of Units";
- Holding Trust Note Indenture. See "Holding Trust – Holding Trust Notes";
- Administration Agreement. See "Management of the Trust – Administration Agreement";
- Delegation Agreement. See "Management of the Trust – Delegation Agreement";
- Voting and Exchanging Trust Agreement. See "Declaration of Trust and Description of Units – Special Voting Units";
- Unanimous Shareholders' Agreement. See "Unanimous Shareholder Agreement";
- Support Agreement. See "Management of The Trust – Administration Agreement";
- \$75,000,000 Extendible Revolving Term Credit Facility Credit Agreement. This is an unsecured three-year extendible revolving letter of credit facility with The Bank of Nova Scotia maturing on September 30, 2010. AltaGas may borrow up to \$25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowing on the facility bear fees and interest at rates relevant to the nature of the draw made;
- \$375,000,000 Extendible Revolving Term Credit Facility Credit Agreement, which was increased from \$300,000,000 in January 2008. This is an unsecured extendible revolving three-year credit facility with Royal Bank of Canada, Canadian Imperial Bank of Commerce, Bank of Montreal, The Bank of Nova Scotia, Alberta Treasury Branches and National Bank of Canada maturing on September 30, 2010. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made;

- Trust Indenture between the Trust and Computershare Trust Company of Canada dated May 12, 2005 related to the issuance and sale of debentures pursuant to the Trust's medium-term note program; and
- \$120,000,000 Secured Revolving Term Credit Facility Credit Agreement. This is a secured revolving credit facility with Canadian Imperial Bank of Commerce, Royal Bank of Canada, National Bank of Canada and Alberta Treasury Branches, maturing on June 28, 2008, which was assumed as part of the acquisition of Taylor. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, or bankers' acceptances. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. The revolving facility is secured by a first ranking floating-charge debenture on all of Taylor's assets.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The General Partner and AltaGas Ltd. are not aware of any material interest, direct or indirect, of any director or officer of the General Partner or AltaGas Ltd., any director or officer of a corporation that is an insider or subsidiary of the Trust, or any other insider of the Trust, or any associate or affiliate of any such person, in any transaction since the commencement of the Trust's last three completed financial years, or in any proposed transaction, that has materially affected or would materially affect the Trust or any of its subsidiaries.

LEGAL PROCEEDINGS

AltaGas Ltd. is not aware of any material legal proceedings to which the Trust or its affiliates is a party or to which their property is subject.

INTERESTS OF EXPERTS

The auditors of the Trust are Ernst & Young LLP, Chartered Accountants, 1000, 440-2nd Ave. S.W., Calgary, Alberta T2P 5E9. The Trust's consolidated financial statements as at December 31, 2007 and for the year then ended have been filed under National Instrument 51-102 in reliance on the report of Ernst & Young LLP, independent chartered accountants, given on their authority as experts in auditing and accounting. As of December 31, 2007, the partners and employees of Ernst & Young LLP collectively owned less than 1 percent of the Trust's outstanding Trust units.

ADDITIONAL INFORMATION

Additional information, including directors and officers remuneration and indebtedness, principal holders of the Trust's securities, options to purchase the Trust's securities, and interests of insiders in material transactions, where applicable, is contained in the Trust's 2008 Information Circular, which is expected to be filed on or about March 20, 2008 in connection with the Annual Meeting of unitholders to be held April 24, 2008.

Additional financial information is contained in the Trust's consolidated financial statements for the year ended December 31, 2007 and management's discussion and analysis contained in the 2007 Annual Report of the Trust.

The Trust routinely files all required documents through the SEDAR system and on its own website. Internet users may retrieve such material through the SEDAR website www.sedar.com. The Trust's website is located at www.altagas.ca, but the Trust's website is not incorporated by reference into this Annual Information Form.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent for the Trust units and Exchangeable units is Computershare Trust Company of Canada, 600, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

The registrar and trustee for the Trust's medium-term notes is Computershare Trust Company of Canada, 710, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

EFFECTIVE DATE

Unless otherwise specifically herein provided, the information contained in this Annual Information Form is stated as at December 31, 2007.

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. Constitution

The Board of Directors (the "Board") of AltaGas General Partner Inc. (the "General Partner" or the "Corporation") in accordance with the Delegation Agreement among the Trust, the General Partner and the Trustee, has established an Audit Committee (the "Committee") to serve as the Audit Committee of the Trust. Such Committee shall be in compliance with the guidelines for corporate governance of The Toronto Stock Exchange ("TSX") and any regulatory or legal authority having jurisdiction over the Trust.

The Committee shall supervise the audit of the Trust's financial records and will ensure the adequacy and effectiveness of its policies and procedures regarding the Trust's financial reporting, internal accounting, financial controls, management information and risk management.

II. Membership

Following each annual meeting of unitholders of the Trust, the Board shall elect from its Members, not less than three (3) Directors to serve on the Committee (the "Members"). The Members and the Chair of the Committee are nominated and elected by the Board. Every Audit Committee Member must be:

- A Director of the Corporation;
- Independent; and
- Financially literate.

No Member of the Committee shall be an officer or employee of the Corporation or any other subsidiary or affiliate of the Trust. Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of the Corporation. Each Member shall hold office until the Member resigns or is replaced, whichever first occurs.

The Board will appoint a Member as Chair of the Committee on an annual basis.

The Corporate Secretary of AltaGas Ltd. shall be secretary to the Committee unless the Committee directs otherwise.

III. Meetings

The Committee shall convene no less than four times per year at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, or an officer of the Corporation or of AltaGas Ltd. A minimum of twenty-four (24) hours notice of each meeting, plus a copy of the proposed agenda, shall be given to each Member. The Corporate Secretary and Members of management shall attend whenever requested to do so by a Member.

A meeting of the Committee shall be duly convened if two Members are present. Where the Members consent, and proper notice has been given or waived, Members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting.

In the absence of the chair of the Committee, the Members may choose one (1) of the Members to be the chair of the meeting.

The external auditor will be given notice of and be provided the opportunity to attend every meeting of the Committee.

The Audit Committee will hold in camera sessions with management, the internal and external auditors as may be deemed appropriate by the Members.

Minutes shall be kept of all meetings of the Committee by the Corporate Secretary or designate of the Corporate Secretary.

IV. Duties and Responsibilities

The Committee shall, as permitted by and in accordance with the requirements of the Canada Business Corporations Act, the Delegation Agreement, the Articles and By-Laws of the Corporation and any legal or regulatory authority having jurisdiction, periodically assess the adequacy of procedures for the public disclosure of financial information and review on behalf of the Board and report to the Board the results of its review and its recommendation regarding all material matters of a Financial Reporting and Audit nature, including, but not limited to the following main subject areas:

- (a) Financial Statements, including Managements Discussion and Analysis;
- (b) Reports to Unitholders and others;
- (c) Annual and Interim Press releases regarding financial results;
- (d) Internal controls;
- (e) Audits and reviews of financial statements of the Trust and its subsidiaries;
- (f) Filings to securities regulators;
- (g) Review and approval of issuer's hiring policies re: current and former partners and employees of the external auditor;
- (h) Pre-approve non-audit work undertaken by the external audit firm; and
- (i) Accounting and Auditing Irregularity Reporting Policy.

The Committee shall ensure satisfactory procedures for receipt, retention and resolution of complaints and for the confidential, anonymous submission by employees regarding any accounting, internal accounting controls or auditing matters.

The full Board will be kept informed of the Committee's activities by a report at each regular meeting of the Board.

The Committee will review the relevance and adequacy of this Mandate on at least an annual basis and will provide recommendations to the Governance Committee of the Board.

V. External Auditor

The Audit Committee shall recommend the appointment of the external auditor annually. Once appointed by the Unitholders, the external auditor shall report directly to Audit Committee.

The Audit Committee shall pre-approve all non-audit services provided by the external auditor, and shall have direct responsibility for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, including the resolution of disagreements between the external auditor and management.

VI. Relations with Management

The Committee will ensure that it coordinates its activities with the Chief Financial Officer on audit and financial matters and will:

- Meet regularly with Management to discuss areas of concern;
- Review and assess the quality of the executives involved in financial reporting process; and
- Ensure Management provides adequate funding to the Committee so that it may independently engage and remunerate the Auditor and any advisors.

VII. Committee Timetable

The major activities of the Committee will be outlined in an annual Schedule.

AltaGas

Well connected. ▢

AltaGas Income Trust
1700, 355 - 4th Avenue S.W.
Calgary, AB T2P 0J1
Tel: 403-691-7575
Fax: 403-691-7576
www.altagas.ca



NEWS RELEASE

ALTAGAS FILES 2007 YEAR-END FINANCIAL DISCLOSURE DOCUMENTS AND TAYLOR BUSINESS ACQUISITION REPORT

Calgary, Alberta (March 3, 2008) – AltaGas Income Trust (AltaGas or the Trust) (TSX: ALA.UN) today announced that its Consolidated Financial Statements and accompanying notes for the year ended December 31, 2007, as well as the related Management's Discussion and Analysis, are now available online at www.altagas.ca. The Business Acquisition Report related to the acquisition of Taylor NGL Limited Partnership is also available on the Trust's website. All documents have been filed with the relevant securities regulators and are posted on the Canadian Securities Administrators' website at www.sedar.com.

Summary year-end disclosure was provided on February 27, 2008 in the fourth quarter and year-end news release and during a conference call held that same day. The transcript for that conference call will be available on the Trust's website shortly.

The print versions of the 2007 Annual Report, Notice of Annual Meeting and Management Proxy Circular will be mailed to AltaGas unitholders in late March. AltaGas' annual meeting will be held at 3:00 p.m. MDT on April 24, 2008 at The Metropolitan Centre in Calgary, Alberta.

AltaGas Income Trust is one of Canada's largest and fastest growing energy infrastructure organizations. The Trust creates value by acquiring, growing and optimizing gas and power infrastructure, including a focus on renewable energy sources.

AltaGas Income Trust's units are listed on the Toronto Stock Exchange under the symbol ALA.UN. The Trust is included in the S&P/TSX Composite Index, the S&P/TSX Income Trust Index and the S&P/TSX Capped Energy Trust Index.

This news release contains forward-looking statements. When used in this news release, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties, including without limitation, changes in market, competition, governmental or regulatory developments, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this news release, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this news release as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in, or incorporated by reference in this news release, should not be unduly relied upon. Such statements speak only as of the date of this news release. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

For further information contact:

Media
C.J. Wilkins
(403) 691-9890
cj.wilkins@altagas.ca

Investment Community
Stephanie Labowka-Poulin
(403) 691-7136
stephanie.labowka-poulin@altagas.ca

Website: www.altagas.ca
Investor Relations
1-877-691-7199
investor.relations@altagas.ca

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FORM 13-502F1

OFFICE OF INTERNATIONAL
CORPORATE FINANCE

CLASS 1 REPORTING ISSUERS -- PARTICIPATION FEE

Reporting Issuer Name: ALTAGAS INCOME TRUST

Fiscal year end date used

to calculate capitalization: December 31, 2007

Market value of listed or quoted securities:

Total number of securities of a class or series outstanding as at the issuer's most recent fiscal year end

(i)

56,057,438

Simple average of the closing price of that class or series as of the last trading day of each month of the fiscal year (See clauses 2.11(a)(ii)(A) and (B) of the Rule)

(ii)

\$26.24

Market value of class or series

(i) X (ii) =

(A)

1,470,947,173

(Repeat the above calculation for each class or series of securities of the reporting issuer that was listed or quoted on a marketplace in Canada or the United States of America at the end of the fiscal year)

(B)

Market value of other securities:

(See paragraph 2.11(b) of the Rule)

(Provide details of how value was determined)

(C)

(Repeat for each class or series of securities)

(D)

Capitalization

(Add market value of all classes and series of securities)

(A) + (B) + (C) +

(D) =

1,470,947,173

Participation Fee

\$29,700

(From Appendix A of the Rule, select the participation fee beside the capitalization calculated above)

New reporting issuer's reduced participation fee, if applicable
(See section 2.6 of the Rule)

Participation fee	X	Number of entire months remaining in the issuer's fiscal year	=	_____
_____	12			

Late Fee, if applicable
(As determined under section 2.5 of the Rule)

SEC File # 333-149111
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Washington, DC
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Management's Discussion and Analysis

The Management's Discussion and Analysis (MD&A) of operations and financial statements presented herein are provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Income Trust (AltaGas or the Trust) as at and for the year ended December 31, 2007 compared to 2006. This MD&A dated March 3, 2008 should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2007.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among others things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this

MD&A, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Financial outlook information contained in this MD&A about prospective results of operations, financial position or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for the purposes other for which it is disclosed herein.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of the Trust, including its annual MD&A and audited financial statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's website or directly through the SEDAR system at www.sedar.com.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipelines Partnership, PremStar Energy Canada Limited Partnership and ECNG Limited Partnership (collectively the operating subsidiaries). The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is derived from operating income earned from partnership interests held by AltaGas Holdings Limited Partnership No. 1 (AltaGas LP #1), from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the holders of the units, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

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OVERVIEW OF THE BUSINESS

AltaGas is a gas and power infrastructure business with physical links along the energy value chain, operating experience that has a strong track record of achieving efficiency, reliability and profitability of its assets, knowledge of the markets it serves and the financial discipline to create long-term value for its investors. AltaGas is focused on maximizing the profitability and long-term value of its current assets and growing its energy infrastructure business through the acquisition and development of assets and services that are linked to its existing business.

The gas business is comprised of gathering and processing assets which include natural gas gathering pipelines and processing facilities. The gathering systems move natural gas from producing wells to processing facilities and the processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation. The processing assets also include ethane and natural gas liquids (NGL) extraction and field fractionation facilities. Extraction plants straddle major natural gas transmission pipelines and reprocess the natural gas to extract and recover ethane and NGLs. The gas business also includes natural gas and NGL transmission pipelines. Transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. Another key component of the AltaGas gas business is the ability to use its market knowledge and expertise to optimize the assets to create value. AltaGas provides energy consulting and supply management services to non-residential end-users, buys and resells energy, gas transportation and storage, and markets gas for producers to further enhance value by optimizing the infrastructure.

The power business consists of 353 MW of coal-fired base-load generation acquired under power purchase arrangements (PPAs). The PPAs are owned through a 50 percent ownership interest in the Sundance B PPAs, giving AltaGas the rights to Sundance B power output and ancillary services until December 31, 2020. The Sundance plant is located 70 km west of Edmonton, Alberta. AltaGas' power generation portfolio also includes the Bear Mountain Wind Park near Dawson Creek, British Columbia, which will have a capacity of approximately 100 MW and is currently under construction, 25 MW of gas-fired power peaking capacity acquired under a capital lease, as well as a 25 percent interest in a 7-MW run-of-river hydroelectric generation capacity through a 25 percent interest in the Boston Bar Partnership. AltaGas owns 14.4 MW of natural gas-fired peaking capacity which is currently being installed at two gas processing sites. AltaGas has an interest through the GreenWing Energy Development Limited Partnership (GEDLP) to develop wind power and gas-fired power generation and has a preferred relationship with a major turbine supplier to develop wind projects in three states in the United States. AltaGas also owns lease rights and agreements to develop approximately 70 MW of run-of-river hydroelectric projects.

Vision

AltaGas' vision is to become the leading Canadian energy infrastructure company with a focus across Canada and the northern United States, by capitalizing on its solid underlying business, operational expertise and financial strength. To achieve its vision, AltaGas will focus on increasing the value and profitability of its existing assets and on growing and diversifying through development and acquisition of gas and power infrastructure.

Strategy

The Trust's strategy is to deliver sustainable and increasing earnings and cash flow from its existing assets as well as from the growth and diversification of its business. It will achieve this by linking the operating experience of its gas and power business with its energy market knowledge and financial discipline and strength. AltaGas expects the growth in its business to be evenly split between gas and power over the long term. The strategy is to enhance value by providing value-added services along the energy value chain of gathering, processing, transporting and marketing of natural gas and the generation and sale of electricity.

By positioning the Trust strategically along the energy value chain, AltaGas links energy producers to energy users. AltaGas pursues opportunities that offer strong financial returns and growth potential and identifies, evaluates and targets opportunities that are accretive to earnings and cash flow and that provide the appropriate balance between risk and return.

Despite the softening in natural gas prices over the past 18 months and uncertainty in the Alberta royalty regime, AltaGas management believes that North America's natural gas producing regions will continue to require significant investment in drilling, gathering and processing assets to support the levels of production needed to meet long-term demand for natural gas as consuming markets continue to compete for supply. Management also believes that the long-term fundamentals of the power business are strong. North American demand for power is expected to continue growing, with an emphasis on renewable power. In Alberta, marginal supply additions, strong economic growth and the upcoming retirement of older thermal power plants will likely continue to result in high power prices. The sound long-term supply and demand fundamentals for gas and power form the basis of AltaGas' strategy.

The Trust's objectives are to:

- Maximize the profitability and long-term value of its existing infrastructure and services;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee, and margin-based contract terms and with minimal or managed exposure to commodity prices;
- Grow its gas and power infrastructure and related services through consolidations, expansions and acquisitions in Canada and the northern United States;
- Focus on projects that are accretive to earnings and cash flow and exhibit the appropriate risk and return balance;
- Diversify infrastructure by fuel source, contractual terms, exposure to industry cycles and geographic location;
- Focus on expanding its clean energy footprint such as wind and hydroelectric power, as well as natural gas-fired generation;
- Generate green credits through technology such as acid gas injection and renewable projects to decrease environmental impacts and hedge against environmental costs; and
- Maintain the Trust's investment-grade credit ratings.

In 2007 the Trust made significant progress in growing its business through the offer to acquire Taylor NGL Limited Partnership (Taylor), the expansion of current operations and the development of the Bear Mountain Wind Park. The Taylor acquisition, completed on January 10, 2008, created a more balanced and diversified business with the addition of the RET Complex, the Harmattan Complex, the Younger and Joffre extraction plants as well as two NGL pipelines. The Taylor acquisition also included the 25 percent interest in the Boston Bar hydroelectric plant which increased AltaGas' power generation portfolio by 1.8 MW, as well as two run-of-river hydroelectric projects under development with a planned 20 MW of capacity contracted for 40 years with BC Hydro.

The Taylor acquisition is an example of AltaGas' strategy at work. The newly acquired assets are low-risk, long-life energy infrastructure that are underpinned by long-term contracts with strong counterparties providing stable and predictable cash flows. With the acquisition, AltaGas' infrastructure touches more than 2 Bcf/d of natural gas and AltaGas operates four extraction plants serving the Western Canada Sedimentary Basin (WCSB). The contribution from the extraction business will be increased, thereby diversifying revenue sources. The assets also have the appropriate risk profile, with 12 percent of total extraction volumes exposed to commodity price fluctuations while maintaining the opportunity to limit downside risk and shut-in production when frac spreads are low. AltaGas' new interest in the existing hydroelectric generation plant and run-of-river projects under development have expanded its renewable energy footprint.

Specified Investment Flow-Through (SIFT) Tax and Other

On June 12, 2007 the SIFT tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. Prior to this legislation, AltaGas' future income tax liability reflected only those temporary differences in the Trust's subsidiaries that were subject to tax. While net income in 2007 was significantly reduced by this future income tax adjustment, the non-cash future income tax expense had no impact on current cash flows.

In December 2007 the federal government substantively enacted rate reductions which lowered corporate tax rates for the years 2008 to 2012 and beyond. The federal corporate tax rates were reduced from 19.5 percent in 2008 to 15 percent in 2012 and future years. These rate reductions resulted in rate reductions to the trust taxation rate from 31.5 percent as enacted by the federal government in second quarter 2007 for years commencing 2011, to 29.5 percent in 2011 and 28.0 percent thereafter.

AltaGas' management will continue to review and consider alternatives for the most efficient organizational structure for AltaGas. The Trust is registered in Alberta where a corporation is subject to lower overall tax rates than the rate that will apply to trusts in 2011. The federal government has indicated that it will allow corporate conversions to occur on a tax deferred basis but the specific rules have not yet been established. Subject to the tax deferred mechanism being available, AltaGas expects that it will convert to a corporation prior to 2011 but expects to take advantage of the flow-through mechanism of the trust structure until then, unless there are more compelling reasons for converting prior to 2011. AltaGas has always executed its strategy as a tax-efficient corporation and focused on key traditional financial metrics such as earnings per unit and return on equity. It does not rely on the trust structure to sustain its business. Its assets are long-life, low-risk energy infrastructure, the value of which is underpinned by strong energy supply and demand fundamentals. The infrastructure assets generate strong, predictable and sustainable cash flows and are expected to continue to enhance value for all investors over the long term.

2007 Highlights

AltaGas:

- Offered to acquire all the outstanding units of Taylor not previously held by AltaGas. The acquisition was completed on January 10, 2008. The Taylor acquisition increased extraction capacity by 1,040 Mmc/d, added 140,000 Bbls/d in transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing (FG&P) segment's capacity by 150 Mmc/d. In addition, the Power Generation segment increased with the 25 percent ownership of the 7-MW Boston Bar power plant and acquisition of 20 MW of hydroelectric generation under development;
- Announced its first energy infrastructure investment in Ontario with the 50 percent ownership of the 5.3 Bcf Sarnia Airport Storage Pool Project;
- Invested \$28 million in field gathering and processing infrastructure, primarily in coal bed methane producing areas;
- Acquired and commenced installation of 14.4 MW of additional gas-fired peaking capacity at the Bantry and Parkland gas processing facilities;
- Generated net income of \$108.8 million (\$1.90 per unit) compared to \$114.5 million (\$2.06 per unit) in 2006. In 2007 net income included \$5.4 million related to the tax on income trusts which was substantively enacted in second quarter 2007;
- Reported EBITDA of \$173.7 million (\$3.03 per unit), up from \$173.1 million (\$3.12 per unit) in 2006;
- Generated cash from operations of \$183.3 million (\$3.19 per unit) in 2007 compared to \$146.9 million (\$2.65 per unit) in 2006;
- Generated funds from operations⁽¹⁾ of \$162.9 million (\$2.84 per unit) compared to \$161.7 million (\$2.91 per unit) in 2006;
- Increased monthly distributions by 3 percent from \$0.17 to \$0.175 beginning with the September distribution;
- Declared and granted a special distribution of one AltaGas Utility Group Inc. (Utility Group) common share for every 100 trust and exchangeable units of AltaGas valued at \$0.076 per unit;
- Signed agreements with Aeolis Wind Power Corporation (Aeolis) and Peace Energy Renewable Energy Cooperative (Peace) to exchange their equity interests in Bear Mountain Wind Limited Partnership (BMWLP) for a royalty agreement giving AltaGas 100 percent ownership of BMWLP;
- Entered into an engineering, procurement and construction (EPC) agreement with Enercon GmbH for the wind turbines required for BMWLP. AltaGas also entered into a long-term service and maintenance agreement with Enercon to operate and maintain the turbines; and
- Announced a significant multi-year financial commitment valued at more than \$500,000 to support Cross Country Canada. This commitment is the largest philanthropic contribution ever for the Trust and will support the nation's high-performance cross country skiers and fuel their drive to the podium.

⁽¹⁾ Includes financial measures not included under generally accepted accounting principles. Please see discussion in the Non-GAAP Financial Measures section of this MD&A.

CONSOLIDATED RESULTSYears ended December 31
(\$ millions)

	2007	2006	2005
Revenue	1,428.4	1,362.6	1,502.3
Unrealized gains on risk management	1.1	–	–
Net revenue ⁽¹⁾	324.0	318.9	296.9
EBITDA ⁽¹⁾	173.7	173.1	155.5
EBITDA before unrealized gains on risk management ⁽¹⁾	172.6	173.1	155.5
Operating income ⁽¹⁾	126.6	126.7	108.1
Operating income before unrealized gains on risk management ⁽¹⁾	125.5	126.7	108.1
Net income	108.8	114.5	90.3
Net income before tax-adjusted unrealized gains on risk management ⁽¹⁾	109.3	114.5	90.3
Net income before tax ⁽¹⁾	114.7	113.4	89.0
Total assets	1,199.8	1,109.6	1,068.3
Total long-term liabilities	329.0	340.5	335.5
Net additions (disposals) of capital assets	21.8	70.5	(139.4)
Distributions declared ⁽²⁾⁽³⁾	118.6	110.8	100.0
Cash flows			
Cash from operations	183.3	146.9	112.3
Funds from operations ⁽¹⁾	162.9	161.7	129.0

(\$ per unit)

EBITDA ⁽¹⁾	3.03	3.12	2.88
EBITDA before unrealized gains on risk management ⁽¹⁾	3.01	3.12	2.88
Net income	1.90	2.06	1.67
Net income per diluted unit	1.89	2.06	1.67
Net income before tax-adjusted unrealized gains on risk management ⁽¹⁾	1.90	2.06	1.67
Net income before tax ⁽¹⁾	2.00	2.04	1.65
Distributions declared ⁽²⁾⁽³⁾	2.065	1.995	1.85
Cash flows			
Cash from operations	3.19	2.65	2.08
Funds from operations ⁽¹⁾	2.84	2.91	2.39
Units outstanding (millions)			
Weighted average number of units outstanding for the period (basic)	57.4	55.5	54.0
Weighted average number of units outstanding for the period (diluted)	57.4	55.5	54.1
End of period	58.1	56.4	54.6

⁽¹⁾ Non-GAAP financial measure. See discussion in the Non-GAAP Financial Measures section of this MD&A.⁽²⁾ Distributions declared of \$0.175 per unit per month commencing in August 2007. From August 2006 to July 2007 distributions of \$0.17 per unit per month were declared. From March 2006 to July 2006 distributions of \$0.165 per unit per month were declared. From August 2005 to February 2006 distributions of \$0.16 per unit per month were declared. From January 2005 to July 2005 distributions of \$0.15 per unit per month were declared.⁽³⁾ Excludes share distribution of AltaGas Utility Group Inc. shares in September 2007 providing an additional non-cash distribution of \$0.076 per unit. Excludes share distribution as a result of the spin-out of the Natural Gas Distribution (NGD) segment in November 2005, providing an additional non-cash distribution of \$0.54 per unit.**2007 Consolidated Financial Review**

Net income in 2007 was \$108.8 million compared to \$114.5 million in 2006. Excluding the SIFT tax of \$5.4 million recorded in 2007, the \$6.1 million non-cash tax benefit due to the reduced federal tax rates recorded in fourth quarter 2007, and the non-cash tax benefit of \$6.6 million due to tax rate reductions recorded in 2006, net income for the year ended December 31, 2007 was in line with 2006. Adjusting for these one-time tax items, net income was \$108.1 million in 2007 compared to \$107.9 million in 2006. Net income increased mainly due to higher power prices received on hedged

sales and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher extraction volumes exposed to frac spreads, higher frac spreads, a one-time gain from the sale of oil and gas production assets and lower interest expense. These increases were offset by lower revenues from unhedged sales due to lower Alberta spot power prices, lower throughput in the FG&P segment, the expiration of the Genesee power contract, higher operating and administrative costs, lower earnings in the Energy Services segment and a one-time charge related to non-recoverable costs incurred on a development project.

Consolidated net revenue for 2007 was \$324.0 million compared to \$318.9 million in 2006. The increase was due to higher hedge prices and lower costs in the Power Generation segment, new facilities and higher rates in the FG&P segment, higher frac spread-exposed volumes and higher frac spreads, and a one-time gain on the sale of oil and natural gas production assets. The increases were partially offset by the expiration of the Genesee power contract, lower throughput in the FG&P segment, a lower contribution from the oil and gas assets sold in May 2007 and decreased earnings in the Energy Services segment.

Operating and administrative expense for 2007 was \$150.3 million compared to \$145.8 million in 2006. The increase was due to additional costs related to new facilities, higher compensation and administrative costs and a one-time charge related to non-recoverable costs incurred on a development project.

Amortization expense for 2007 was \$47.1 million compared to \$46.4 million in 2006. The increase was primarily due to new and expanded facilities in the FG&P segment, partially offset by the sale of oil and natural gas production assets and the one-time write down of \$0.6 million of goodwill on a non-core investment in 2006.

Interest expense in 2007 was \$11.9 million compared to \$13.3 million in 2006. The decrease was primarily due to a lower average debt balance of \$234.9 million compared to \$274.1 million in 2006, partially offset by slightly higher borrowing rates. The average borrowing rate in 2007 was 5.3 percent compared to 4.9 percent in 2006.

Income tax expense for 2007 was \$5.9 million compared to an income tax recovery of \$1.1 million in 2006. The increase was mainly due to the non-cash charge of \$5.4 million to record future income tax liabilities for differences between the accounting and tax basis of AltaGas' assets and liabilities as a result of the SIFT tax, the \$6.6 million non-cash tax benefit recorded in 2006 due to Alberta and federal income tax rate reductions and a \$1.6 million tax impact on unrealized gains related to risk management assets and liabilities. These increases were partially offset by the difference between the \$6.1 million non-cash tax benefit due to the federal rate reductions enacted in late 2007 and the future income tax recovery of \$0.6 million from the sale of oil and natural gas production assets.

2008 Consolidated Outlook

With the addition of the new assets to AltaGas' current energy infrastructure and services business, AltaGas expects to deliver a significant increase in earnings and cash flow in 2008. The majority of the acquired assets will be included in the Extraction and Transmission (E&T) segment. AltaGas expects the proportion of its operating income from this segment to increase from 25 percent of overall operating income from all business segments in 2007 to approximately 40 percent in 2008.

In 2008 AltaGas expects operating income to increase as a result of the contribution of the new assets from the Taylor acquisition, higher hedge prices for power and continued strong frac spreads. The current forward curve for Alberta spot power prices is in the low to mid-\$70/MWh range, higher than the average Alberta Pool price for 2007. NGL volumes produced are expected to double year-over-year resulting in NGL volumes exposed to frac spreads increasing from approximately 9 percent of total volumes in 2007 to 12 percent in 2008. The current forward curve for frac spread is in the low to mid-\$20/Bbl range.

2006 Consolidated Financial Review

This section provides an overview of AltaGas' financial performance based on the audited annual Consolidated Financial Statements included in the 2006 Annual Report. All references to per unit amounts pertain to basic units outstanding for the period. Certain prior-year figures have been reclassified to conform to the current year's presentation.

Net income in 2006 was \$114.5 million (\$2.06 per unit) compared to \$90.3 million (\$1.67 per unit) in 2005. The increase was due to higher power prices received on both hedged and unhedged power volumes, lower power transmission costs, higher NGL frac spreads, higher extraction volumes and lower interest expense, partially offset by higher operating and administrative expense and higher income taxes.

In addition the Trust recorded a \$6.6 million non-cash future income tax benefit in 2006 as a result of a reduction in federal and Alberta corporate income tax rates. Net income in 2005 included one-time contributions of \$7.5 million related to the Trust's ownership of Taylor units, a full-year contribution from the Genesee power contract and the contribution from the Natural Gas Distribution (NGD) segment which was spun out on November 17, 2005.

Net revenue for 2006 was \$ 318.9 million compared to \$296.9 million in 2005. The increase was mainly due to higher prices received on the sale of power and lower power transmission costs (\$42.2 million), new facilities, higher processing fees and higher operating cost recoveries in the FG&P segment (\$15.1 million), higher NGL frac spreads and higher volumes processed in the extraction business (\$7.0 million), higher equity earnings in the Corporate segment (\$3.0 million), the acquisition of the assets and liabilities of iQ2 Power Corporation (iQ2) in late 2005 (\$2.2 million) and \$2.1 million higher net revenue from the gas-fired peaking plants. The increases in net revenue were partially offset by the spin-out of the NGD business in November 2005 (\$29.0 million), lower throughput in the FG&P segment (\$5.2 million), the expiration of the Genesee power contract in March 2006 (\$2.5 million) and \$1.6 million lower contribution from the oil and gas properties. In 2005 net revenue included one-time contributions of \$8.6 million related to the Trust's ownership of Taylor units.

Operating and administrative expense for 2006 was \$145.8 million, compared to \$141.4 million in 2005. The increase was due to higher administrative and compensation costs, additional costs from new FG&P facilities and the acquisition of iQ2. The increases were partially offset by the spin out of the NGD segment which reported operating and administrative costs of \$16.0 million in 2005. Increased third-party costs of approximately \$1.0 million were incurred in 2006 over 2005 to meet new certification requirements for reporting issuers mandated by the Canadian Securities Administrators.

Amortization expense for 2006 was \$46.4 million compared to \$47.4 million last year. The decrease was due to the spin out of the NGD segment which reported \$6.8 million in amortization expense in 2005, partially offset by increases related to the growth in capital assets resulting from acquisitions and internal expansion projects, higher depletion expense related to the Trust's oil and gas properties and higher amortization related to energy services contracts and relationships. In 2006 AltaGas also recorded a goodwill impairment of \$0.6 million related to a non-core investment.

Interest expense in 2006 was \$13.3 million compared to \$19.1 million in 2005. The decrease was due to lower average debt balances (2006 – \$274.1 million, 2005 – \$326.1 million) as a result of \$85.4 million in debt repayment in late 2005 using the proceeds from the spin-out of the NGD segment and due to higher funds from operations. Also contributing to the lower interest expense was a lower average borrowing rate of 4.9 percent in 2006, compared to 5.6 percent in 2005, mainly due to the August 2005 refinancing of term debt at lower rates.

Income tax recoveries for 2006 were \$1.1 million compared to recoveries of \$1.3 million in 2005. Income tax recoveries decreased as a result of higher net income before tax in 2006, partially offset by a non-cash future tax benefit of \$6.6 million that resulted from federal and Alberta income tax reductions in 2006. Income taxes reported in 2005 also included an expense of \$1.1 million related to the NGD segment, an adjustment of future tax balances that resulted in a recovery of \$1.6 million and a lower effective tax rate in respect of the Taylor capital gain reported in 2005.

Capital Outlook

AltaGas' strategy is to maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. In order to execute its strategy, AltaGas expects capital expenditures to be approximately \$125 million and \$250 million in 2008 and 2009 respectively and to be split approximately 60 percent gas and 40 percent power in both years. Included in the estimated expenditures is approximately \$50 million annually for gas infrastructure projects. This estimate is based on projects that are in various stages of development and historical levels of expenditures in the FG&P segment. The estimate does not include the cost of developing the four potential run-of-river projects described below.

Bear Mountain Wind Park

AltaGas currently owns 100 percent interest of the BMWLP and the Bear Mountain Wind Park. AltaGas intends to finance the project, which is expected to cost approximately \$190 million, through its credit facilities and by including one or more third-party investors in the project, which would reduce AltaGas' ownership in the wind park to approximately 45 percent. The Bear Mountain Wind Park will have a capacity of approximately

100 MW and is backstopped by a 25-year electricity purchase agreement with BC Hydro. AltaGas entered into an EPC agreement with Enercon to supply and install wind turbines. AltaGas has also entered into a long-term service agreement with Enercon to operate and maintain the wind turbines. AltaGas commenced construction activities in December 2007 and intends to have the project completed by November 2009. Expenditures for 100 percent of the project are expected to be approximately \$55 million in 2008 and \$120 million in 2009. AltaGas has hedged approximately 21 percent of the total euros required for the project.

Sarnia Airport Storage Pool Project

AltaGas owns a 50 percent interest in the Sarnia storage project, with the other 50 percent being owned by Market Hub Partners Canada L.P., a Spectra Energy Corp. partnership. The project is expected to provide more than 5 Bcf of working capacity and deliverability of approximately 52 Mmcfd and will include three new wells, a compressor plant and approximately 18 kilometres of pipeline. The project is in the early stages of development, is subject to various regulatory and environmental approvals and is expected to be in full operation by mid-2009. AltaGas' share of the project is expected to cost approximately \$25 million.

Log Creek and Kookipi Creek Hydroelectric Projects

AltaGas is developing two hydroelectric facilities to be located on the Fraser River near Hope, British Columbia. The Log Creek and Kookipi Creek projects are each 10-MW run-of-river hydroelectric facilities in the final stages of permitting and licensing. Both facilities have 40-year electricity purchase agreements with BC Hydro. The plants are expected to be in operation in 2010 and to cost a total of approximately \$60 million to \$70 million.

Run-of-River Hydroelectric Plants Under Development

In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the ability to develop approximately 50 MW of hydroelectric power generation in British Columbia. The four new projects are at various stages of development, with the 14 MW Rainy River project near Gibson, British Columbia in an advanced development stage. Rainy River is expected to be operational in 2010. AltaGas anticipates the power from its hydro projects will be sold to B.C. Hydro through its Clean Power Call process. All of the development projects are subject to various regulatory and environmental approvals.

Harmattan Co-Streaming Project

The proposed Harmattan Co-streaming Project is expected to bring natural gas from TransCanada's Alberta system to the Harmattan Complex for processing to recover ethane, propane, butane and condensate. The Harmattan Co-streaming Project hearing at the Alberta Energy Resources Conservation Board (ERCB) is pending the outcome of the inquiry into the NGL extraction convention (the Inquiry). The Inquiry is anticipated to be completed by the fall of 2008. Upon approval, construction of the co-streaming project will commence, requiring approximately 12 months to complete. The project, as currently envisioned, is expected to cost in the range of \$70 million to \$90 million.

TAYLOR NGL LIMITED PARTNERSHIP 2007 RESULTS

AltaGas acquired all outstanding units of Taylor it did not already own effective January 10, 2008. The results described below are intended to provide the reader with a brief description of Taylor's 2007 results of operations to allow the reader to determine the potential impact of the Taylor acquisition on the results of the Trust.

In 2007 Taylor recorded a net loss of \$42.1 million compared to net income of \$28.7 million in 2006. Adjusting for the SIFT tax of \$69.1 million, the impact of mark-to-market accounting for financial instruments loss of \$5.9 million and gain of \$0.8 million in 2007 and 2006 respectively and compensation costs of approximately \$1 million related to the offer by AltaGas to acquire the units of Taylor, net income in 2007 was \$33.9 million compared to \$27.9 million in 2006.

Taylor recorded net revenue of \$109.9 million in 2007 compared to \$101.9 million in 2006. NGL sales averaged 21,126 Bbls/d in 2007 compared to 20,465 Bbls/d in 2006, up 3 percent and setting a new annual record. Gas volumes processed were 443 Mmcfd in 2007, compared to 452 Mmcfd in 2006.

Operating and administrative expense in 2007 was \$51.2 million compared to \$48.1 million in 2006. Included in 2007 was approximately \$1 million in higher compensation costs related to the offer by AltaGas to acquire the units of Taylor.

In 2007 Taylor's EBITDA was \$59.6 million compared to \$53.8 million in 2006, excluding the impact of mark-to-market gains and losses on financial instruments and one-time compensation costs related to the offer by AltaGas to acquire the units of Taylor.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other funds or entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures by AltaGas.

Net Revenue (\$ millions)	2007	2006	2005
Net revenue	324.0	318.9	296.9
Add: Cost of sales	1,104.4	1,043.7	1,205.4
Revenue (GAAP financial measure)	1,428.4	1,362.6	1,502.3

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of natural gas and power affect both revenue and cost of sales.

Operating Income (\$ millions)	2007	2006	2005
Operating income	126.6	126.7	108.1
Add (deduct): Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization.

Operating Income Before Unrealized Gains on Risk Management (\$ millions)	2007	2006	2005
Operating income before unrealized gains on risk management	125.5	126.7	108.1
Add (deduct): Unrealized gains on risk management	1.1	—	—
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Operating income before unrealized gains on risk management is a measure of the Trust's profitability from its principal business activities prior to accounting for how these activities are financed, how the results are taxed, and how the impact of gains from risk management activities affected operations. Operating income before unrealized gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses and amortization of capital assets.

EBITDA (\$ millions)	2007	2006	2005
EBITDA	173.7	173.1	155.5
Add (deduct): Amortization and goodwill impairment	(47.1)	(46.4)	(47.4)
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to how these activities are financed, how assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

**EBITDA Before Unrealized Gains
on Risk Management (\$ millions)**

	2007	2006	2005
EBITDA before unrealized gains on risk management	172.6	173.1	155.5
Add (deduct): Unrealized gains on risk management	1.1	-	-
Amortization and goodwill impairment	(47.1)	(46.4)	(47.4)
Interest	(11.9)	(13.3)	(19.1)
Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

EBITDA before unrealized gains on risk management is a measure of the Trust's operating profitability. EBITDA before unrealized gains on risk management provides an indication of the results generated by the Trust's principal business activities prior to accounting for the impact of unrealized gains from risk management activities and how business activities are financed, how assets are amortized or how the results are taxed. EBITDA before gains on risk management is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue adjusted for unrealized gains on risk management less operating and administrative expenses.

**Net Income Before Tax-Adjusted Unrealized
Gains on Risk Management (\$ millions)**

	2007	2006	2005
Net income before tax-adjusted unrealized gains on risk management	109.3	114.5	90.3
Add (deduct): Unrealized gains on risk management	1.1	-	-
Income tax expense on risk management	(1.6)	-	-
Net income (GAAP financial measure)	108.8	114.5	90.3

Net income before tax-adjusted unrealized gains on risk management is a better reflection of performance than net income as changes related to risk management are based on estimates related to commodity prices and foreign exchange rates over time. Net income before tax-adjusted unrealized gains on risk management is calculated from the Consolidated Statement of Income and Accumulated Earnings and is defined as net income plus unrealized gains on risk management and less income tax expense.

Net Income Before Tax (\$ millions)

	2007	2006	2005
Net income before tax	114.7	113.4	89.0
Add (deduct): Income taxes	(5.9)	1.1	1.3
Net income (GAAP financial measure)	108.8	114.5	90.3

Net income before tax is a better reflection of performance because it is not dependent on how those results are taxed which can change from year-to-year. Net income before tax is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net income less income tax expense.

non-gaap financial measures

Funds From Operations (\$ millions)	2007	2006	2005
Funds from operations	162.9	161.7	129.0
Add (deduct): Net change in non-cash working capital and asset retirement obligations settled	20.4	(14.8)	(16.7)
Cash from operations (GAAP financial measure)	183.3	146.9	112.3

Funds from operations is used to assist management and investors in analyzing operating performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash flow from operations or other cash flow measures calculated in accordance with Canadian GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement costs.

RESULTS OF OPERATIONS BY SEGMENT

Operating Income (\$ millions)	2007	2006
Field Gathering and Processing	18.2	25.4
Extraction and Transmission	39.1	35.2
Power Generation	94.6	90.9
Energy Services	2.0	2.8
Corporate	(27.3)	(27.6)
	126.6	126.7
Operating income before unrealized gain on risk management	125.5	126.7

FIELD GATHERING AND PROCESSING

The FG&P segment consists of 77 gathering and processing facilities in 30 operating areas in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets.

This segment includes the RET complex which is comprised of three interconnected processing facilities and related gathering systems that were acquired effective January 10, 2008 through Taylor. Subsequent to the Taylor transaction, AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, including 359 Mmc/d of sour gas capacity. AltaGas operates 74 of its 77 facilities.

77
facilities in 3 provinces
within the WCSB.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmc/d, which distinguishes it from most of its competitors in western Canada.

The FG&P segment's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	135.1	139.1
Net revenue	127.4	129.7
Operating and administrative expense	83.3	80.1
Amortization expense	25.9	23.6
Goodwill impairment	–	0.6
Operating income	18.2	25.4

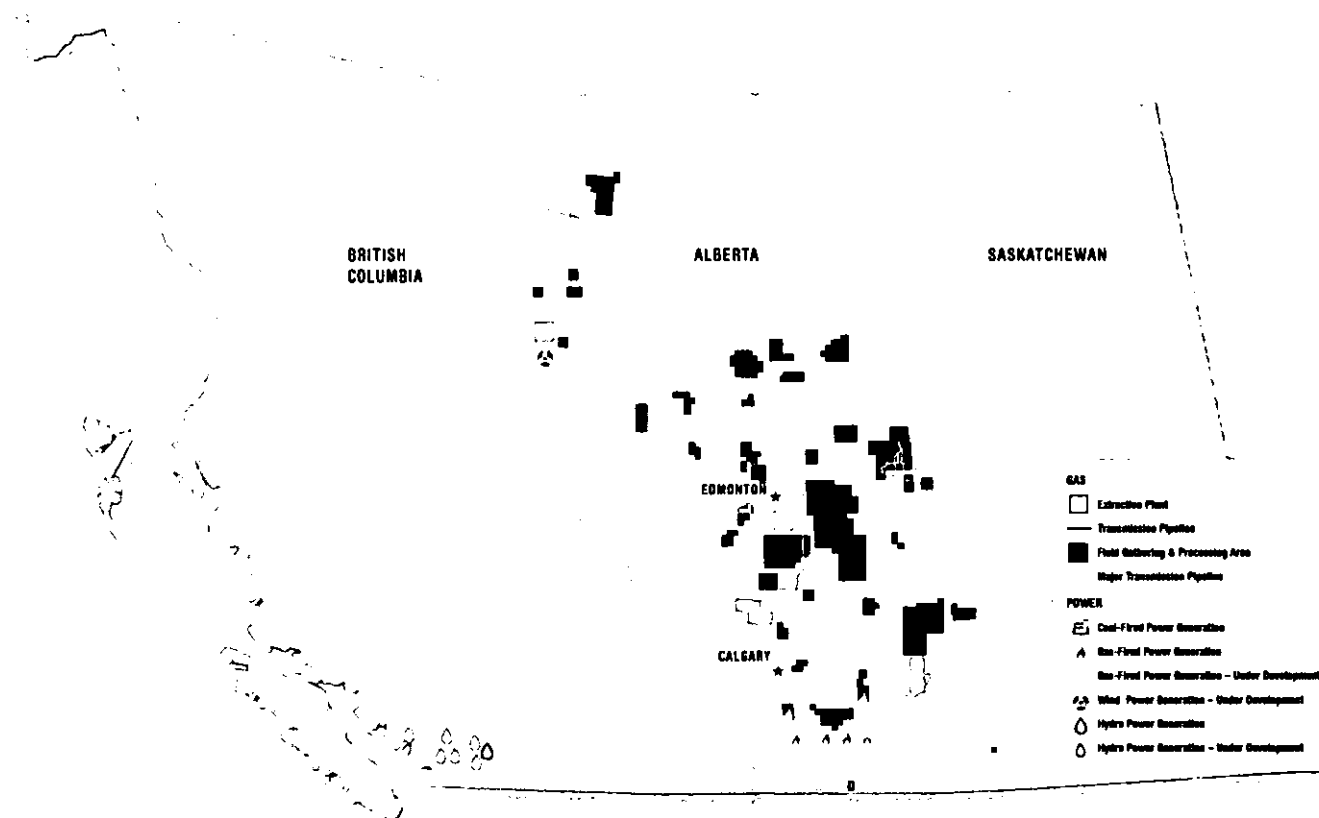
Operating Statistics	2007	2006
Capacity (Mmcf/d) ⁽¹⁾	1,023	1,021
Throughput (gross Mmcf/d) ⁽²⁾	511	549
Throughput (gross annual Mmcf/d) ⁽²⁾	527	555
Capacity utilization (percent) ⁽³⁾	52	54
Average working interest (percent) ⁽¹⁾	91	92

⁽¹⁾ As at December 31.

⁽²⁾ Fourth quarter average.

⁽³⁾ Average for the period.

AltaGas Field Gathering and Processing Assets



As at March 3, 2008.

field gathering and processing

In the FG&P segment, operating income was \$18.2 million in 2007 compared to \$25.4 million in 2006. The decrease was due to lower throughput (\$7.6 million), lower equalization and minimum volume adjustments (\$3.1 million), higher general and administrative costs (\$1.0 million) and higher amortization due to expansions (\$0.6 million). The decreases were partially offset by the contribution from new plants (\$2.7 million) and higher rates and other revenues of \$2.4 million.

Capacity increased due to the addition of the new Acme and Corbett Creek facilities, which were partially offset by the sale of the Ikhil Joint Venture and the redeployment of the Del Bonita assets. Throughput in 2007 averaged 527 Mmc/d compared to 555 Mmc/d in 2006. The 5 percent decrease was primarily due to natural declines and lower producer activity, partially offset by new facility throughput additions of 11 Mmc/d from AltaGas' new Clear Prairie, Clear Hills, Princess and Acme facilities. Of the 28 Mmc/d throughput decrease, 16 Mmc/d was attributable to the North district and the balance to the South district. In the North district, the Wabasca area experienced throughput declines of 9 Mmc/d as a result of a less successful drilling program than the previous year. The decline in the South district was due to lower producer activity, partially offset by higher throughput from new wells at South Foothills. Utilization in 2007 was 52 percent compared to 54 percent reported in 2006.

Net revenue in the FG&P segment in 2007 was \$127.4 million compared to \$129.7 million in 2006. New facilities contributed \$6.1 million to net revenue in 2007, and increased rates contributed \$1.5 million. These increases were offset by lower throughput which resulted in a \$7.6 million decline in net revenue and lower routine equalization adjustments of \$1.7 million.

Operating and administrative expense in the FG&P segment in 2007 was \$83.3 million compared to \$80.1 million in 2006. The increase was mainly attributable to new facilities, higher property taxes and higher compensation costs, partially offset by lower operating costs.

Amortization expense in the FG&P segment in 2007 was \$25.9 million compared to \$24.2 million in 2006. The increase was due to new and expanded facilities, partially offset by the sale of the interest in the Ikhil Joint Venture and the write-off of goodwill in fourth quarter 2006.

FG&P Outlook

With the purchase of Taylor completed in January 2008, FG&P will integrate the RET Complex into its FG&P operations. The RET Complex is composed of three interconnected natural gas processing facilities approximately 40 km north of Lethbridge. The RET Complex is capable of handling both sour and sweet natural gas and provides gathering and processing services to approximately 55 producers having approximately 1,200 producing wells. Throughput in the RET Complex averaged 57 Mmc/d in the fourth quarter of 2007.

FG&P expects to report higher results in 2008 than in 2007. The increase is due to the addition of the RET Complex, recontracting at higher rates, optimization of facilities and increased operating cost flowthrough. AltaGas expects throughput to increase in 2008 over 2007 primarily due to the addition of the RET facilities.

AltaGas is working with customers to optimize underutilized assets. The underutilized Sedgewick facility is expected to be connected to the fully utilized Killam and Iron Creek facilities to allow gas to be diverted to Sedgewick and allow increased combined processing for the three facilities. AltaGas expects to increase its gas gathering and processing infrastructure in 2008 through acquisition and development of new facilities as producers reallocate capital from processing to their core activity of exploration and production. Increased drilling activity and producer activity in CBM areas, northwest Alberta and northeast British Columbia is also expected to provide opportunities for expansions, acquisitions and development of gas gathering and processing infrastructure. AltaGas expects to spend approximately \$50 million to grow and optimize its gathering and processing infrastructure in 2008, including gathering systems, capacity expansions and enhancements to its sour gas processing facilities.

AltaGas has experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity has been impacted by lower profitability and uncertainty regarding the new Alberta royalty regime. In 2008 AltaGas expects producer activity to rebound since average operating costs have declined, natural gas prices remain above the lows of 2007 and the completion of the Alberta royalty review should bring greater certainty to the industry. As a result, AltaGas expects demand for gathering and processing facilities to increase, thereby mitigating the impact of natural declines.

Business Strategy and Opportunities

The FG&P segment provides safe and reliable gathering and processing and ancillary services to its customers. The strategic focus is on increasing profitability of the existing infrastructure, increasing market share, servicing Alberta's future CBM production and moving westward to capitalize on increased exploration and drilling activities. While the WCSB is considered to be a maturing basin, AltaGas remains confident in the long-term demand for natural gas, strong natural gas prices and improvements in exploration and drilling technology and hence the long-term viability of the WCSB.

AltaGas' strategy is to:

- Maximize the profitability of the current field gathering and processing infrastructure:
 - Increase revenues by converting contracts to flowthrough operating costs and market based fees;
 - Offer flexible contractual terms and equal access to all producers;
 - Enhance operational efficiencies through consolidation, plant upgrades and integration with other business segments;
 - Integrate operational support for the peaking power plants; and
 - Manage costs and improve reliability.
- Grow its field gathering and processing infrastructure:
 - Expand into areas of unconventional gas production such as CBM, shale gas, and tight gas, where dedicated infrastructure is required to meet processing needs;
 - Expand into areas of high producer activity where there is increasing demand for gas gathering and processing infrastructure such as northwest Alberta and northeast British Columbia;
 - Invest in moveable assets that can be easily and quickly redeployed to new locations, improving operational flexibility and profitability, and responding quickly to producer requirements;
 - Increase working interests to control operations, increase efficiency and reduce operating costs;
 - Acquire underutilized assets that offer upside through increased throughput in areas where production is expected to support the investment; and
 - Construct or acquire and connect complementary facilities to create large facility complexes to capture operating synergies.

There are many opportunities to allow AltaGas to execute its strategy in the FG&P segment to meet the existing and future gathering and processing needs of its customers. In addition to its network of approximately 6,500 km of gathering lines, substantial processing capacity, expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities, approximately 80 percent of the compression units are skid-mounted. This allows AltaGas to relocate units quickly and cost effectively to respond to the changing processing needs of its customers. At present, the majority of gathering and processing infrastructure in western Canada is owned by oil and natural gas producers with 15 to 20 percent of the volumes in the WCSB processed by independent gas processors, including 3 percent processed by AltaGas. AltaGas believes that its strong operating skills and moveable assets create opportunities to work with customers to provide field gathering and processing services in a cost-effective and efficient manner.

New area development comes in large part from the drilling programs of AltaGas' existing and expanding customer base. Reserves analysis indicates that there are significant opportunities to increase natural gas production, including unconventional reserves within the WCSB, many in areas where gathering and processing infrastructure is limited thus providing opportunities for new infrastructure investment.

AltaGas may also see increased opportunities to acquire or build gathering and processing infrastructure from or on half of producers wishing to redeploy capital on exploration and production activities rather than on non-core activities such as processing.

Existing field gathering and processing areas usually have adjoining or overlapping gathering and processing systems. As AltaGas has grown, opportunities to expand by tying in new wells and building or purchasing adjoining facilities and systems have increased.

AltaGas also enhances the value of its gathering and processing infrastructure by integrating with the other business segments. The resulting suite of integrated services such as natural gas transmission, NGL extraction and natural gas and NGL marketing enhances value for its customers and investors.

Risk Management

AltaGas' field gathering and processing facilities process or transport natural gas from the WCSB. Throughput at these facilities is dependent on a number of factors including the level of exploration and development within the WCSB, the long-term supply and demand dynamics for natural gas which impact the longer-term price of natural gas, and the regulatory environment for natural gas market participants. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas throughput and from rising operating costs. AltaGas manages its exposure to financial risk in the FG&P segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Volume declines in the WCSB	- Contract provisions such as take-or-pay, capital cost recovery, area of mutual interest, geographic franchise with economic out, length of term and type of service as well as underpinned capital commitments. - AltaGas owns extensive gathering systems and moveable processing plants and can quickly deploy assets in response to customers' drilling activity and volume variability. - Increase geographic and customer diversity to reduce exposure to any one customer or area of the WCSB. - Expand into areas with strong producer activity, new sources of supply (including unconventional) and limited or fully utilized processing facilities.	- New contracts in 2007 included take-or-pay provisions. - New facilities and expansions underpinned by take-or-pay contracts. \$2.5 million in take-or-pay shortfall revenue in 2007. 29 of 30 operating areas have area of mutual interest provisions. - Approximately 80 percent of compression units are skid-mounted. - Relocated six compressors to optimize horsepower and reduce expenses in Cold Lake area. - In response to producer activity, AltaGas relocated approximately 40 pieces of equipment in 2007. - Approximately 250 customers with no customer representing more than 6 percent of FG&P net revenue during 2007. - Top 10 customers represented 13 percent of consolidated net revenues in 2007. 77 natural gas processing facilities in 30 operating areas in three provinces within the WCSB. - Developed new Acme facility to process CBM. - Built Acme plant and acquired Corbett Creek plant and associated gas gathering systems. These facilities are dedicated to processing CBM gas. - Acquired three facilities in southern Alberta through the Taylor acquisition in an area not previously served by AltaGas.
Increasing operating costs	- Contractual provisions provide for recovery of actual operating costs. - Acquire large working interests and operate facilities in order to control and optimize operations, and maximize efficiencies, customer demand and throughput.	79 percent of contracts include CPI escalators. 39 percent of operating costs were recovered directly from customers in 2007. - Increased operating cost flowthrough contracts to recover 45 to 50 percent of operating costs in 2008. - Operating costs remained flat in 2007. - Average working interest of 91 percent. - Operate 74 of 77 FG&P facilities.
Natural gas price fluctuations	Toll-for-service structure independent of commodity prices; revenues are a function of volumes processed.	The majority of processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput.
Environmental and safety	AltaGas has strong safety and environmental management systems, which it continually strives to improve.	Princess and Turin gas plants continued acid gas injection, reducing carbon dioxide and sulphur dioxide emissions to virtually zero.
Government and regulatory changes	Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	- Active participation in industry committees and regulatory forums. - Increased activity by CBM producers due to the new Alberta royalty regime increasing demand for AltaGas processing facilities.

EXTRACTION AND TRANSMISSION

The Extraction and Transmission segment consists of interests in four ethane and NGL extraction plants, one fractionation facility, five natural gas transmission systems and one condensate pipeline. The Taylor acquisition in January 2008 added one wholly owned extraction plant and two NGL pipelines in Alberta, increased AltaGas' ownership in the Joffre plant from 50 percent to 100 percent and added interests in an extraction plant in British Columbia.

Extraction

AltaGas owns extraction plant processing capacity through its interest in two extraction plants at Empress, Alberta, an extraction plant at Joffre, Alberta and another in Edmonton, Alberta. Also included in the extraction business is AltaGas' Bantry field fractionation facility. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was

554 Mmc/d at December 31, 2007. With the Taylor transaction effective January 10, 2008, AltaGas added the Harmattan Complex in Alberta, ownership interest in the Younger Extraction Plant in British Columbia and increased its ownership of the Joffre Extraction Plant in Alberta to 100 percent. The Harmattan Complex has natural gas licensed inlet capacity of 490 Mmc/d, a deep cut NGL extraction unit, NGL fractionation net capacity of 25,000 Bbls/d and NGL terminal facilities. The Younger Extraction Plant, with NGL extraction ownership of 56.7 percent, has net processing capacity of 425 Mmc/d and NGL fractionation and terminal ownership of 100 percent with net capacity of 25,000 Bbls/d. The increased ownership of the Joffre plant added net capacity of 125 Mmc/d and terminalling with net capacity of 5,200 Bbls/d. AltaGas operates the Edmonton Ethane Extraction Plant, the Joffre Extraction Plant, the Bantry field facility and the Younger Extraction Plant.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted, they are sold as natural gas for their heating value at the prevailing natural gas price. As ethane and NGLs, the components are sold at higher prices that reflect the premium value for each of the individual commodities. In most cases the NGLs recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGLs to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGLs are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. NGLs, predominantly ethane, are feedstock for ethylene production.

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements.

Ownership in 6 of the 10 Canadian extraction facilities.

Extraction Production
Bbls/d



Transmission

AltaGas owns five natural gas transmission systems and one condensate pipeline. Effective with the Taylor acquisition on January 10, 2008 the transmission business includes the Ethylene Delivery System (EDS) and the Joffre Feedstock Pipeline (JFP). The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas. The EDS is a 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. JFP is a 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The Suffield System in southeastern Alberta accounted for 72 percent of transmission net revenue in 2007 and has capacity of 400 Mmcfd. The majority of the Suffield System's capacity is currently contracted by EnCana through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter.

Contractual volume commitments are expected to increase annually from approximately 370,000 GJ/d in 2007 to approximately 406,000 GJ/d in 2010 and will decline thereafter.

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The Kahntah pipeline transports natural gas from British Columbia to Alberta and is contracted on an annual basis. The Porcupine Hills pipeline in southwest Alberta is a single-shipper condensate pipeline. The Summerdale and Battle Lake pipelines transport natural gas in central Alberta.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	142.9	149.1
Net revenue	67.4	63.2
Operating and administrative expense	20.3	20.3
Amortization expense	8.0	7.7
Operating income	39.1	35.2
Operating Statistics	2007	2006
Extraction inlet capacity (Mmcfd) ⁽¹⁾	554	554
Extraction volumes (Bbls/d) ⁽²⁾	20,108	19,696
Transmission volumes (Mmcfd) ^{(2) (3)}	407	400
Frac spread (\$/Bbl) ^{(2) (4)}	\$ 21.38	\$ 18.47

⁽¹⁾ As at December 31.

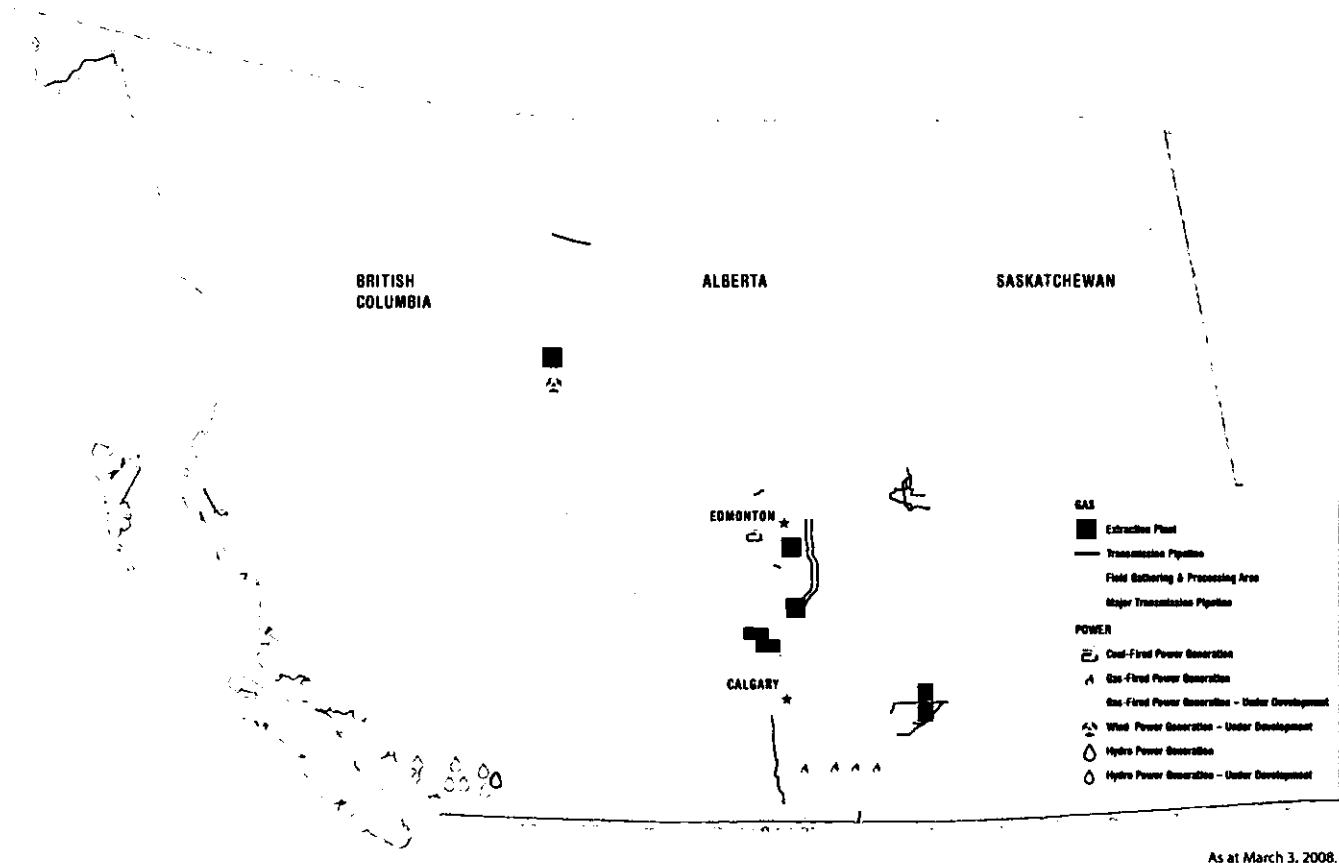
⁽²⁾ Average for the period.

⁽³⁾ Excludes condensate pipeline volumes.

⁽⁴⁾ AltaGas reports an indicative frac spread or NGL margin, expressed in dollars per barrel of NGL, which is derived from Edmonton postings for propane, butane and condensate and the daily AECO natural gas price.

AltoGas Extraction and Transmission Assets

extraction and transmission



Operating income in the E&T segment in 2007 was \$39.1 million, up from \$35.2 million in 2006. The increase was primarily due to higher frac spreads and higher frac spread-exposed NGL volumes in the extraction business and the expansion of the Cold Lake transmission system.

In 2007, average ethane and NGL volumes increased primarily as a result of the increased ownership at one of the extraction plants and higher utilization. Transmission volumes also increased slightly to 407 Mmcf/d from 400 Mmcf/d primarily due to higher deliveries on the Suffield transmission system.

Net revenue was \$67.4 million in 2007, compared to \$63.2 million in 2006. The increase was primarily due to higher frac spreads (\$1.4 million), higher extraction volumes (\$1.8 million), the expansion of the Cold Lake transmission system and higher committed volumes on the Suffield system.

Operating and administrative expense in the E&T segment in 2007 was \$20.3 million for 2007 and 2006. Lower costs due to lower volumes processed through the Edmonton Extraction Plant were offset by the increased costs at one of the Empress facilities due to the increased ownership.

Amortization expense in 2007 was \$8.0 million compared to \$7.7 million in 2006. The increase was due to the increased ownership at one of the Empress facilities and the enhanced ethane recovery project at the Edmonton extraction plant.

E&T Outlook

Results in the E&T segment are expected to increase materially in 2008. The acquisition of Taylor has added approximately 1 Bcf/d of inlet processing capacity, 23,500 Bbls/d of NGL production and 140,000 Bbls/d of NGL transportation capacity. Operating income in the E&T segment as a percentage of total operating income from all business segments is expected to increase from 25 percent in 2007 to approximately 40 percent in 2008. Volumes are also expected to increase as a result of opportunities to optimize and upgrade the infrastructure and consolidate extraction facilities in AltaGas' operating areas resulting in increased utilization and hence earnings.

Approximately 90 percent of the revenue from the E&T segment is based on long-term fee-for-service, cost-of-service and minimum volume commitment long-term contracts. The segment is expected to continue to deliver strong performance and predictable and stable returns. Commercial arrangements are structured to manage exposure to commodity price movements such that the majority of the volumes have downside protection to volatility and the remaining volumes allow AltaGas to participate in upside opportunity. These remaining volumes are driven by frac spreads which are expected to remain above recent historical levels. NGL prices continue to track the crude oil price which is expected to stay strong through 2008 while natural gas prices are expected to remain relatively flat resulting in continued strong frac spreads. Approximately 12 percent of extraction volumes are exposed to frac spread and approximately 45 percent of those volumes have been hedged at approximately \$21/Bbl for 2008. The remaining volumes remain exposed to frac spread. The current forward curve for frac spread is in the low to mid-\$20/Bbl range.

In second quarter 2008 a 23-day maintenance turnaround is planned at one of the facilities and is expected to cost approximately \$4.0 million in direct costs and lost operating income. In third quarter 2008 there are planned turnarounds for a total of 48 days at three facilities which are expected to cost approximately \$1.8 million in direct costs and lost operating income.

AltaGas has been an active participant in the Inquiry to ensure its existing and future extraction business is not negatively impacted. Proposed changes to the existing NGL extraction convention have been analyzed and mitigation strategies formulated. AltaGas believes that with the strategies in place, the outcome of the Inquiry will have no material impact on the extraction business.

On March 8, 2007, the Government of Alberta introduced legislation to reduce greenhouse gas emissions. The Climate Change and Emissions Management Amendment Act, along with its accompanying Specified Gas Emitters Regulation (SGER), state that facilities that emit more than 100,000 tonnes of greenhouse gases per year must reduce their emissions intensity by 12 percent per annum starting July 1, 2007. The Harmattan Complex falls within the scope of the legislation as its greenhouse emissions are slightly above 100,000 tonnes per year. Management's initial calculations for emissions intensity for 2007 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty.

In the transmission business, the full year of the Cold Lake expansion is expected to increase results compared to 2007 and AltaGas expects to pursue expansions similar to the Cold Lake Expansion, which may further enhance returns in the segment. An arrangement to utilize an unused portion of the Ethylene Delivery System has been completed and is also expected to result in higher results in 2008.

Business Strategy and Opportunities

The E&T segment provides safe and reliable processing and transportation services to its customers. The strategic focus is on optimizing current infrastructure and increasing throughput and market share to improve profitability through long-term fixed-fee or cost-of-service contracts. The main business driver in the extraction business is the volume of ethane and NGLs produced which is directly correlated to the volume of natural gas processed, natural gas composition, recovery efficiency of the extraction plant, plant on-line time, contractual arrangements and commodity price.

The E&T segment's business strategy is to:

- Maximize the profitability of the existing extraction and transmission infrastructure:
 - Increase throughput and utilization of existing extraction and transmission infrastructure;
 - Recontract for services to increase returns;
 - Execute commercial arrangements that have long-term fixed-fee or cost-of-service components;
 - Use frac spread hedges to lock-in margins and reduce exposure to frac spread volatility;
 - Operate plants to mitigate downside risk when frac spreads are low;
 - Lever existing assets and services to capture accretive growth; and
 - Offer marketing, transportation management and processing services in cooperation with the Energy Services and FG&P segments.
- Grow its extraction and transmission infrastructure:
 - Acquire and develop new facilities; and
 - Increase working interest ownership of partially owned plants.

There are many opportunities to enable AltaGas to execute its strategies in the E&T segment. Extraction growth opportunities may arise from plant modifications to increase product recoveries at facilities in which AltaGas already has ownership, by increasing interests in existing extraction plants, through construction of new facilities and by increasing throughput through additional extraction agreements. Extraction plant opportunities typically reflect a long-term, cost-of-service ethane processing arrangement contracted with Alberta ethylene producers, long-term NGL fixed processing fee arrangements and a small percentage of short-term sales of NGLs based on an Edmonton or U.S. index.

The natural gas supply to the Joffre and Edmonton extraction plants depends on natural gas demand pull from central Alberta's petrochemical industry, residential and other commercial usage. The economy in the area remains strong, resulting in sustained volumes of gas processed at these plants. The Empress extraction plants rely on the supply of natural gas from natural gas export volumes, while the Younger extraction plant is supplied from the robust natural gas producing region of northeast British Columbia. Growth in NGL production at Younger will depend on the ability to increase natural gas volumes processed at the plant. The Harmattan Complex is a significant service provider in its capture area. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and optimize asset utilization and increase profitability. The Harmattan Co-Streaming Project is also expected to increase processing capability to the plant. Overall, the diverse nature of its extraction infrastructure should allow AltaGas to increase throughput, utilization and profitability.

The extraction business is also strongly influenced by frac spreads. As frac spreads are at historically high levels and are expected to remain high into the foreseeable future, AltaGas expects to show strong results from this business.

The transmission business' main value drivers are the fees earned, which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market. Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where pipeline capacity is limited or non-existent. In capturing opportunities, AltaGas focuses on long-term, cost-of-service type contractual arrangements. Increased activity in heavy oil in the Cold Lake area is expected to provide AltaGas with additional opportunities to expand its Cold Lake system in a similar fashion to the expansion completed in 2007. Drilling activity in areas served by AltaGas' other transmission assets is also expected to provide opportunities to expand infrastructure and increase utilization of the assets.

Risk Management

AltaGas' extraction facilities and transmission assets process or transport natural gas, NGLs and condensate from the WCSB. Utilization of these facilities is dependent on a number of factors including natural gas supply, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the longer-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for NGL market participants. The extraction business is further influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes plus as separate marketable commodities and their value as constituents of the natural gas stream. AltaGas manages its exposure to financial risk in the E&T segment using the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term decline in throughput and gas composition variability	- Contract provisions underpin capital commitments. - Long-term contracts independent of throughput. - Collaborate with Energy Services segment to increase volumes through the extraction facilities. - Expand existing facilities or acquire or construct new facilities.	- Majority of contracts are multi-year. - In 2007 75 percent of NGL production under long-term, fixed-fee arrangements. - Ethane production sold under long-term, cost-of-service or fixed-fee contracts. - Utilization at Empress facilities above 98 percent in 2007 despite a 23-day shutdown in May. 99 percent of net revenue from transmission contracts are cost-of-service, take-or-pay or fixed-fee. - Expanded the Cold Lake natural gas transmission system. - Completed the Taylor acquisition and added Harmattan Complex, the Younger Plant, the remaining ownership in Joffre Extraction Plant, and two NGL pipelines.
Commodity price fluctuations	- Contracting terms and processing fees independent of commodity prices with fee-for-service or cost-of-service provisions. - Hedging practice to reduce exposure to frac spread volatility and lock-in margins when the opportunity arises to increase profitability.	- NGL is reinjected or extraction operations are reduced or suspended when uneconomical to produce. - Less than 9 percent of total extraction production was exposed to frac spreads in 2007. - Ethane production sold under long-term, cost-of-service or fixed-fee contracts. 75 percent of NGL production under long-term, fixed-fee arrangements. - The transmission business is not directly affected by commodity price fluctuations. - Hedged 45 percent of volumes exposed to frac spread for 2008.
Increasing operating costs	- Acquire large working interests to control and optimize operations and maximize efficiencies. - Structure fees to recover actual operating costs.	- Significant portions of cost-of-service contracts provide for operating cost recovery. - Some extraction contracts allow recovery of certain operating costs, including shrinkage gas attributable to that production. - Operator of all transmission assets and four of six extraction facilities. - Maintenance management programs ensure tight cost controls and equipment reliability.
Environmental and safety	AltaGas has strong safety and environmental management systems, which it continually strives to improve.	Maintained its Certification of Recognition from Alberta Human Resources and Employment.
Government and regulatory changes	Regulatory and commercial personnel work closely to monitor and react to regulatory issues.	Active participation in industry committees and regulatory forums.

POWER GENERATION

AltaGas has 353 MW of coal-fired base-load capacity through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired peaking capacity. The Trust also has a 25 percent interest in a 7 MW run-of-river hydroelectric generation facility in British Columbia as a result of the Taylor acquisition. AltaGas' 378 MW of installed power capacity served approximately 5 percent of Alberta's power demand in 2007. In 2007 AltaGas also purchased 14.4 MW of gas-fired peaking capacity which is currently being installed at two FG&P locations in Alberta. The Power Generation segment is primarily engaged in the sale of electricity and ancillary services to the Alberta wholesale market.

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output. The 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to a specified target level of 86 percent of the Sundance B plants' rated capacity and to ancillary services until December 31, 2020.

175 MW
of renewable generation
under development.

Results in the Power Generation segment are largely driven by generator availability, hedge prices (for the portion of capacity that is hedged) and Alberta spot prices (for the portion of capacity that is not hedged). The relationship among production, spot prices and cost of sales is specified in the PPAs. Generally, AltaGas is compensated when power production is less than target levels, at a rate based on the previous 30-day average spot price (RAPP). Similarly, if generation from the PPAs is above target, AltaGas is obligated to provide the owner of the generation facility, TransAlta Corporation (TransAlta), financial compensation based on the difference between actual availability and target availability, multiplied by the RAPP. The financial exposure may be positive or negative depending on the difference between the current Alberta spot price and RAPP. The majority of the cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Alberta Power Pool trading charges. The price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation, rather than the prevailing market price for coal.

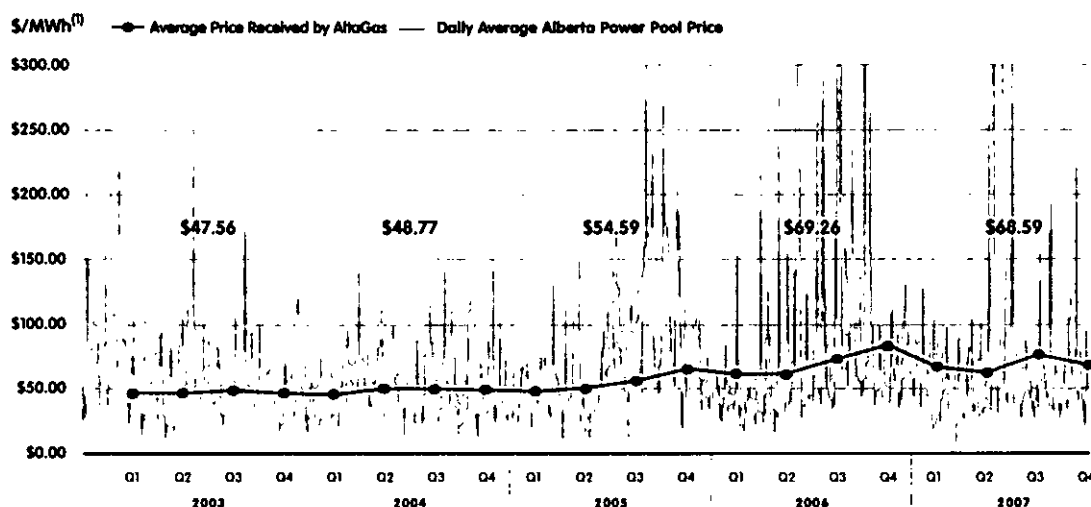
AltaGas also leases, operates and maintains 25 MW of gas fired generation. The lease began in September 2004 and includes an option at the end of the initial term of 10 years to renew for a further 15 years or to purchase the assets. The Energy Services segment manages the gas requirement and the units are dispatched from the Edmonton extraction plant. This 25 MW of gas-fired peaking capacity provides fuel diversity to AltaGas' power business and provides partial backstopping to outages at Sundance. In addition, due to their quick ramp up capability, the peaking plants provide revenue from the sale of energy and ancillary services. Construction is underway for an additional 14.4MW of gas-fired peaking capacity at the Bantry and Parkland gas processing facilities. Upon connection to the electricity grid, the new gas-fired peaking plants will increase the Trust's peaking capacity by 58 percent and further increase operational flexibility and backstopping to the Sundance B PPAs.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	182.5	199.4
Net revenue	104.2	99.6
Operating and administrative expense	2.1	1.3
Amortization expense	7.5	7.4
Operating income	94.6	90.9

Operating Statistics	2007	2006
Volume of power sold (GWh)	2,661	2,878
Price received on the sale of power (\$/MWh) ⁽¹⁾	68.59	69.26
Alberta Power Pool average spot price (\$/MWh) ⁽¹⁾	66.84	80.48

⁽¹⁾ Average for the period.



⁽¹⁾ Chart truncated at \$300.00; daily average Alberta power pool price reached as high as \$999.99/MWh.

Operating income in the Power Generation segment was \$94.6 million for 2007 compared to \$90.9 million for 2006. The increase was due to higher power prices received on hedged sales, lower PPA costs and lower transmission costs. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices, the expiration of the Genesee contract and costs incurred to comply with Alberta's SGER.

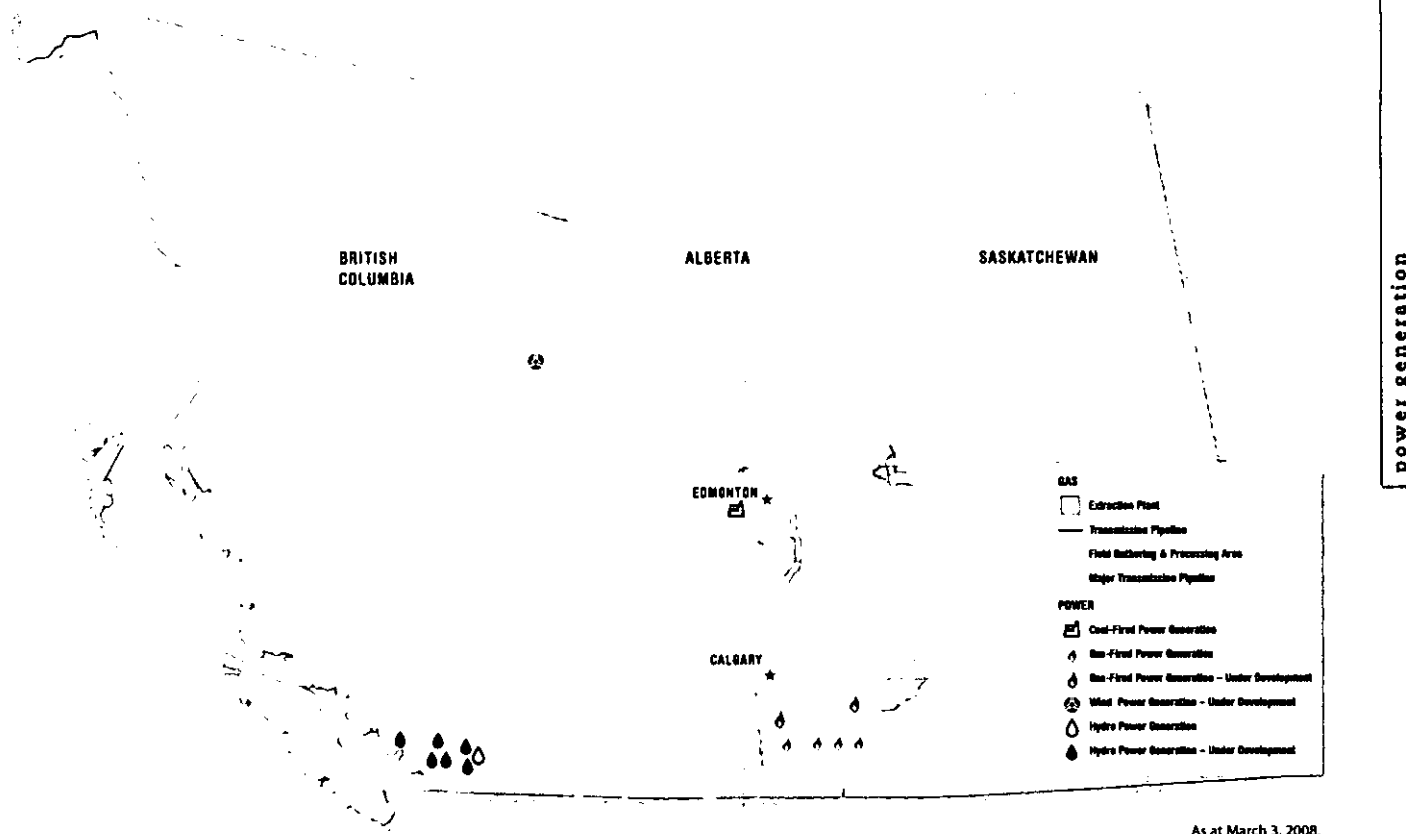
The volume of power sold in 2007 was lower than in 2006 primarily as a result of the Genesee contract expiration on March 31, 2006.

Net revenue was \$104.2 million for 2007 compared to \$99.6 million for 2006. The increase included \$34.6 million due to higher hedge prices, \$9.4 million due to lower PPA costs mainly as a result of a favourable 30-day RAPP during the Sundance B planned outage and lower transmission costs of \$3.2 million. These increases were partially offset by lower revenue from unhedged sales due to lower Alberta spot power prices (\$35.8 million), the expiration of the Genesee contract (\$4.1 million), \$2.0 million of costs incurred to comply with Alberta's SGER and approximately \$0.5 million in other fixed and variable costs.

Operating and administrative expense of \$2.1 million in 2007 was higher than the \$1.3 million reported in 2006, primarily due to the operating and maintenance services AltaGas began providing to the leased peaking plants in March 2007.

Amortization expense of \$7.5 million in 2007 was similar to \$7.4 million in 2006.

AltaGas Power Generation Assets



Power Generation Outlook

Operating income in the Power Generation segment is expected to be higher in 2008 than in 2007. The contribution from hedged power volumes is expected to be higher than in 2007 as a result of average hedge prices of approximately \$76/MWh in 2008 compared to \$66/MWh in 2007. Consistent with AltaGas' hedge program, approximately two-thirds of the power available from the Sundance B PPAs has been hedged and the remaining is exposed to the spot price of power in Alberta. In early 2008, the forward market for power prices indicates that power prices will remain relatively strong, in the low to mid-\$70/MWh range until 2012. PPA costs are expected to be higher in 2008 due to higher power generated. However, as the price for coal purchased through the PPAs is based on pre-defined formulae tied to inflation rather than the prevailing market price of coal, it is not expected to have a significant impact on PPA costs in 2008.

On June 27, 2007 the Alberta government passed the SGER which requires large final emitters to reduce greenhouse gas emissions intensity by 12 percent per year beginning July 1, 2007, to purchase an equivalent amount of offset credits from intra-Alberta sources, or to pay \$15/tonne of emissions over the 12 percent reduction into a provincially administered technology fund. This regulation affects the Sundance facility and is expected to increase 2008 operating expense by approximately \$5 million. To the extent these costs can be recovered through higher power pool prices, by the physical reduction of emissions intensity, or by creating or acquiring offsets, the impact of these costs would be mitigated.

The 14.4 MW of new gas-fired peaking capacity will be integrated into ongoing operations and is expected to be operational in second quarter 2008. Installation of the generating capacity is estimated to cost approximately \$10 million and is expected to be accretive to net income and cash flow once operational.

Revenue from the gas-fired peaking facilities is derived from the sale of energy and ancillary services. Based on the expected spot price for power and natural gas in Alberta for 2008, AltaGas expects the utilization of its gas-fired peaking facilities to average 20 percent. The plants also provide ancillary services, which generate revenue without delivering power to the grid.

Business Strategy and Opportunities

The Power Generation segment consists primarily of AltaGas' 50 percent ownership of the Sundance B PPAs, which are contractual arrangements entitling the Trust to the output from the 353 MW coal-fired base-load Sundance B plant. The Trust's current hedging strategy and its gas-fired peaking plants optimize financial and operating risk related to the PPAs. The Trust's strategy is to maximize the profitability of the existing power assets and to grow its power generation infrastructure and operational capability.

AltaGas' Power Generation strategy is to:

- Maximize the profitability of the existing power assets:
 - Evaluate, modify and refine the power hedge strategies as appropriate to increase earnings stability and growth from the Sundance PPAs;
 - Dispatch the gas-fired peaking capacity in real time to maximize revenue from both energy and ancillary services;
 - Identify and execute opportunities to create value from the regulation of greenhouse gas emissions; and
 - Capitalize on internal synergies and integration efforts with other operating segments.
- Grow its power infrastructure:
 - Acquire and develop power infrastructure supported by strong power supply and demand fundamentals;
 - Acquire and develop power generation projects supported by long-term power sales arrangements;
 - Diversify power generation portfolio by geography and fuel source;
 - Develop operating capability in other fuel sources;
 - Capitalize on increasing demand for clean power by investing in renewable and clean power project development across Canada and the northern U.S.; and
 - Invest in power opportunities such as additional PPAs in Alberta and other jurisdictions.

The supply-demand fundamentals supporting the Power Generation segment remain favourable in North America. AltaGas expects this will continue to support strong power prices especially in Alberta where the Trust is most exposed to power prices. This could increase the profitability of AltaGas' power generation assets allowing AltaGas to earn higher revenues from the sale of power and ancillary services. The expectation of continued strong power prices is supported by the tightening of the electricity reserve margin in Alberta, as transmission constraints are delaying the addition of new generation facilities. In December 2007, the Alberta Electric System Operator (AESO) published a report titled "Future Demand and Energy Outlook, 2007-2027" which projected provincial demand growing at an average annual rate of 3.2 percent over the next five years. Given the demand and supply forecasts, AltaGas expects reserve margins to remain at less than 10 percent until 2011 at which time it is expected to increase to about 15 percent. In early 2008 the forward curve for power prices indicates that prices will remain relatively strong, in the low to mid-\$70/MWh range until 2012. As at December 31, 2007, 93 percent of AltaGas' generation capacity was low-cost base-load coal-fired generation, resulting in strong future earnings in this market environment.

Power generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The planned decommissioning of thermal plants in Ontario and, beginning in 2010, in Alberta, may present additional growth opportunities through the development and ownership of new capacity. In 2006 AltaGas forged relationships with power generation developers to pursue its strategy to grow its renewable energy portfolio. In 2007 the Trust acquired 100 percent of the BMWLP which owns the Bear Mountain Wind Park under construction near Dawson Creek, British Columbia. In July 2007 the GEDLP owned 50 percent by AltaGas, responded to Manitoba Hydro's 300 MW Wind Request for Proposal (RFP). While the partners were not successful in this RFP, GEDLP may bid the projects into future RFPs.

The Power Generation segment is poised for growth with the Bear Mountain Wind Park under construction and expected to be in service in November 2009. At present AltaGas owns 100 percent of the Bear Mountain Wind Park and intends to include one or more third-party investors in the project, which would reduce ownership in the wind park to approximately 45 percent. AltaGas also has several run-of-river hydroelectric projects, including two 10-MW plants with 40-year energy purchase arrangements with BC Hydro, which are currently in the permitting and licensing phase and expected to be in service in 2010. In February 2008, AltaGas acquired four potential run-of-river hydroelectric projects ranging from 6.5 MW to 24 MW. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric power generation in British Columbia. GEDLP has also developed a portfolio of power projects in Canada and the United States that the Trust believes will fuel further growth in its power infrastructure.

Risk Management

The main risks faced in the power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risk related to the deregulation of power and environmental legislation. Power results are generally driven by volumes of power generated, power prices and the cost of power. Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth. The cost of power is driven by operating costs, changes in transmission rates, and reductions in power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	• A disciplined hedging strategy – hedge targets approved by the Board of Directors. • Hedge transactions monitored by the Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedge own electrical demand requirements. • Own and operate gas-fired peaking capacity which backstops the Sundance PPAs and sells energy and ancillary services in volatile markets.	• Financial hedge contracts generally have terms ranging from three to 36 months. • Average sales price received in 2007 was \$68.59/MWh, compared to average monthly Pool price that ranged from a low of \$48.37/MWh in May to a high of \$155.73/MWh in July. • Supply 11 MW for own use and supply approximately 40 MW to Alberta power retail customers. • Peaking plants contributed \$4.3 million to net revenue in 2007 through sales of ancillary services and energy.
Volume of power generation	• PPAs set specified target availability levels. TransAlta is obligated to provide AltaGas financial compensation to the specified target availability level which was 86 percent of rated capacity in 2007. This is accomplished by a financial payment based on the difference between actual availability and target availability, multiplied by the 30-day RAPP. • Diversification of fuel sources and geography. • Hedging strategy balances price and operating risk. • Pursue further diversification through development partnerships and acquisitions. • Reciprocal backstopping agreements with another generator to supply power at a fixed price during force majeure events.	• Minor impact on revenue during 2007 planned outage. • 25 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs. 14.4 MW additional peaking capacity under construction. • Short-term power purchase contracts used to mitigate the impact of 2007 planned outage. • Wind and hydro power projects under development outside Alberta. • Strong operating history at Sundance B with no significant loss as a result of a force majeure event.
Cost of power	• Cost of power from the coal-fired generation based on PPA indices. • Cost of power is not exposed to market price of coal.	• Modest decrease in cost of power from Sundance PPAs in 2007.
Counterparty risk	• Strong credit policies in place. • Counterparty credit reviews continually updated. • Credit thresholds established using conservative credit metrics. • Exposures and impact of price shocks on liquidity closely monitored.	• All financial hedge counterparties are investment-grade. • No counterparty defaults in 2007.
Construction risk	• Major Projects group manages and monitors significant construction projects. • Use EPC contracts where appropriate to manage construction cost risk. • Effective procurement policies and procedures and vendor selection.	• Executed EPC with Enercon for delivery and installation of the Bear Mountain Wind Park turbines.
Lack of community support	• AltaGas has active corporate and regulatory affairs departments.	• Held several events to inform and educate the communities in which AltaGas is developing projects.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Regulatory risk	The PPAs have provisions for financial relief in the event that policies and regulations render them uneconomic.	AltaGas personnel hold influential positions on key industry policy and oversight committees.
Environment and safety risk	- AltaGas has strong safety and environmental management systems which are continuously being monitored for improvements. - Focus on mitigating the impact of the SGER.	- Bantry and Parkland peaking plants will use compressed natural gas to drive the peaking plant starter motors. The compressed gas will then be captured and cycled through the peaking plants rather than vented into the environment. - Potentially capture offsets from existing AltaGas operating facilities. - Possible offset through higher Alberta Power Pool prices.

ENERGY SERVICES

The Energy Services segment consists of two main components: an energy management business providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users; and a gas services business which supports the operations of the FG&P, E&T and Power Generation segments and buys and resells natural gas, transportation and storage. This segment also included a small portfolio of oil and natural gas production assets that were sold in May 2007.

Energy Management

The energy management business consists of providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users. As of January 1, 2007 AltaGas' energy management services are provided under the brand name "ECNG Energy" and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Burnaby, British Columbia.

Adding value
to our infrastructure business.

The majority of the energy management fee-for-service revenues is based on one-to-three-year evergreen contracts, with some extending as far as eight years. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives. The energy management business also manages electricity supplies for AltaGas' internal power demand in the FG&P and E&T segments and sells power to industrial and commercial end-users, thereby providing a longer-term market for hedging power sales.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-user customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

One of the key functions of the Energy Services segment is to support AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas transmission pipelines and provides gas control services to balance gas flows. Gas services markets gas for FG&P customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' gas-fired power peaking plants.

In addition to supporting other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions and managing potential credit exposures. AltaGas also provides energy procurement services for large industrial and utility gas users, and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into the eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has been successful in achieving positive margins while providing improved netbacks for producers.

Over the past several years, AltaGas had accumulated a portfolio of oil and natural gas production assets in connection with larger acquisitions of gathering and processing facilities. These oil and natural gas assets were sold in the second quarter of 2007.

Results of Operations

Financial Results (\$ millions)	2007	2006
Revenue	1,022.5	948.9
Net revenue	20.9	24.7
Operating and administrative expense	15.6	17.1
Amortization expense	3.3	4.8
Operating income	2.0	2.8
Operating Statistics		
Energy management service contracts ⁽¹⁾	1,466	1,394
Average wholesale volumes marketed (GJ/d) ⁽²⁾	388,217	327,057

⁽¹⁾ Active energy management service contracts at the end of the reporting period.

⁽²⁾ Average for the period. Includes volumes marketed directly, volumes transacted on behalf of other operating segments and volumes sold in gas exchange transactions.

Operating income in the Energy Services segment was \$2.0 million in 2007 compared to \$2.8 million in 2006. The decrease was due to non-recurring earnings reported in the energy management business in 2006, higher gas costs to supply a natural gas contract, higher operating and administrative expense and lower contributions from the operations of the oil and natural gas production assets which were sold effective May 31, 2007. These decreases were partially offset by an increased fixed-price commodity and transportation net revenue in the gas services business, growth in both gas and electricity in the energy management business and the one-time pre-tax gain from the sale of the oil and natural gas production assets.

Net revenue was \$20.9 million in 2007 compared to \$24.7 million in 2006. The decrease included a \$4.0 million lower contribution due to lower volumes and prices related to the operation of the oil and gas production assets, \$2.5 million related to non-recurring earnings in the energy management business, and \$1.4 million due to higher gas costs to supply a natural gas contract. These decreases were partially offset by \$2.0 million from higher optimization, transportation, fixed-price and balancing gas margins in the gas services business, the one-time pre-tax gain from the sale of oil and natural gas production assets of \$1.5 million and \$0.5 million from growth in the energy management business.

Operating and administrative expense was \$15.6 million in 2007 compared to \$17.1 million in 2006. The decrease was primarily due to lower costs related to the operation of the oil and natural gas production assets (\$2.0 million), partially offset by \$0.5 million in higher administrative expenses.

Amortization expense in 2007 was \$3.3 million compared to \$4.8 million in 2006. The decrease was primarily due to the sale of the oil and natural gas production assets of \$1.7 million, partially offset by higher amortization of \$0.2 million related to the addition of new information systems to support the business.

Energy Services Outlook

The increased gas infrastructure acquired through the Taylor transaction is expected to provide additional opportunities for the Energy Services business to identify and execute on opportunities to enhance the earnings from these assets. To the extent that the Energy Services segment can do so, this may increase earnings in the segment or contribute to increased earnings in the other operating segments.

The core businesses within the Energy Services segment are the advisory fee-based business servicing non-residential gas and electricity end-users (energy management), and the fixed-margin gas marketing business (gas services). AltaGas expects results in the Energy Services segment in 2008 to be slightly lower than 2007 results, excluding the gain on sale of the oil and gas production assets in 2007. Lower revenues from fixed-price gas sales are anticipated due to the low natural gas price environment. However, the recent acquisition of Taylor will provide the gas services business with an increased geographic footprint and assets to increase its integration opportunities to enhance unitholder value.

The Energy Services segment is an important element in increasing the value of assets in AltaGas' other segments. Energy Services works with the other segments to optimize AltaGas' assets and in this capacity is expected to contribute to earnings growth across all segments.

Business Strategy and Opportunities

The Energy Services segment provides agency advisory services to energy end users in the commercial, institutional, small industrial and agricultural sectors and locks in margin through the buying and selling of natural gas, transportation and storage. The segment also provides value added services to the FG&P, E&T and Power Generation segments and their customers by capitalizing on its in depth knowledge of the energy markets to optimize AltaGas' infrastructure and enhance value.

AltaGas' Energy Services business strategy is to:

- Maximize profitability of its existing business:
 - Identify opportunities for increased synergies and value across AltaGas' infrastructure and services to increase profitability;
 - Create new service offerings and build on national brand development;
 - Increase market penetration of national energy management services in natural gas and electricity;
 - Manage credit and market risk within the risk tolerances established by the Board; and
 - Increase cost efficiency and improve competitive advantage through common processes and marketing efforts.
- Grow Energy Services infrastructure:
 - Add physical infrastructure such as gas storage capacity.

The key value driver in the Energy Services segment is the services provided to the other infrastructure based business segments. The Energy Services segment provides gas control and gas supply contracting services to the FG&P, E&T and Power Generation segments. AltaGas' strategy is to identify additional opportunities to enhance the value of its infrastructure through transactions and support services. This includes identifying opportunities to increase margins earned in transmission, maintain the cost-effective flow of gas through extraction plants and increase services provided to producers.

The Energy Services business provides AltaGas with a portfolio of contracts with locked-in margins over multiple years. These contracts result in stable and predictable earnings and cash flows. However, these transactions require credit support to backstop potential default risk with suppliers and customers. AltaGas allocates capital to this business based on the credit risk profile of the contracts in order to avoid excessive exposure to default risk. The Trust closely monitors the credit and market risk profile of the contracts through metrics such as value at risk and credit event liquidity analysis.

The Energy Services business incurs significant general and administrative (G&A) expenses as it employs high human capital. AltaGas is focused on operating margin as a percentage of G&A and strives to increase this metric through cost efficiencies from common processes, marketing efforts and promotional materials. Sharing of gas and electricity market knowledge across all regions and streamlining the operations to more effectively serve customers across Canada is also expected to result in improved margins.

In 2007 AltaGas announced its first infrastructure project in the Energy Services segment with the development of the Sarnia Airport Storage Pool project in Ontario. This is AltaGas' first investment in storage infrastructure and is expected to be in service in 2009. Access to a storage asset near the Dawn Hub in Ontario is expected to provide AltaGas with the ability to further capitalize on its in-depth knowledge of the eastern gas markets to further enhance unitholder value. Given the long-term supply and demand fundamentals of natural gas and the increasing impact of liquefied natural gas in the North American natural gas markets, storage capacity is expected to play a more strategic role in the buying, selling and transportation of gas. AltaGas expects to pursue further growth opportunities in storage infrastructure to further enhance margins in Energy Services.

Risk Management

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers. The most significant risks in the Energy Services segment are counterparty and commodity price risk. The credit-intensive nature of this business requires balance sheet support to transact fixed-price energy supply purchase and sale agreements.

While long-term fixed-margin contracts provide stable earnings and cash flow, the Trust employs a disciplined approach to credit allocation to mitigate the risk of counterparty default. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty default	• Strong credit policies in place. • Internal credit ratings and thresholds established. • Exposures and impact of price shocks on liquidity are closely monitored. • Diverse customer and supplier base. • Business model in energy management is based on agency arrangements where counterparty credit risk for commodity exists between the supplier and the end-user.	• Majority of counterparties are investment-grade. • In energy management business, customers are aggregated into groups with joint and several liability for payment of fees. • No Energy Services customer represented more than 8 percent of consolidated revenues during 2007. • In 2007 AltaGas added customers in key sectors nationwide. • Purchase natural gas from a wide array of investment-grade suppliers.
Commodity price fluctuation	• Commodity Risk Policy prohibits transactions for speculative purposes. • Strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems and natural gas markets. • Strong customer relationships.	• All gas service transactions are back-to-back with locked-in margins. • Energy management contracts have terms from one to eight years with locked-in fees. • Advisory fee services business experienced renewal rate of 95 percent in 2007. • Market and manage FG&P customers' gas for a fee. • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk.

CORPORATE

The Corporate segment includes the cost of providing corporate services and general corporate overhead, investments in public and private entities and the effects of changes in the value of risk management assets and liabilities. Management makes operating decisions and assesses performance of its operating segments based on realized results and key financial metrics such as return on equity, return on capital and operating income as a percentage of net revenue without the impact of the volatility in commodity prices and foreign exchange rates. Management monitors the impact of mark-to-market accounting as part of the consolidated entity as risk is managed on a portfolio basis. Consequently, the impact of mark-to-market accounting on net income is reported and monitored in the Corporate segment.

Financial Results (\$ millions)	2007	2006
Revenue ⁽¹⁾	5.1	4.4
Net revenue	6.2	4.4
Operating and administrative expense	31.2	29.7
Amortization expense	2.3	2.3
Operating loss	(27.3)	(27.6)
Operating loss before unrealized gains on risk management	(28.4)	(27.6)

(1) Excludes unrealized gains (losses) on risk management.

The operating loss before unrealized gains on risk management was \$28.4 million in 2007 compared to \$27.6 million in 2006. The increased loss was due to \$1.3 million in higher office, computer and compensation costs and \$1.9 million in write-offs related to costs incurred on development projects. These increases were partially offset by \$1.0 million in lower professional and consulting fees, \$0.8 million in higher general and administrative costs allocated to the operating segments and a one-time gain of \$0.4 million on the unwinding of interest rate swaps as a result of the issuance of \$100 million of medium-term notes in January 2007. Effective in second quarter 2007 AltaGas reduced its influence over Taylor and commenced accounting for its interest in Taylor using the cost method. The effect of the change in the accounting method on the operating loss in 2007 was negligible.

Net revenue was \$6.2 million in 2007 compared to \$4.4 million in 2006. The increase was due to the unrealized gain of \$1.1 million related to risk management contracts and back-to-back commodity purchases and sales as a result of the adoption of accounting standards effective January 1, 2007, that require the fair value of all financial instruments to be reflected on the financial statements. On adoption, AltaGas recorded financial statement related assets and liabilities of \$107.8 million and \$110.6 million respectively. The net impact to accumulated earnings and to Other Comprehensive Income on January 1, 2007 was \$0.2 million and \$2.6 million respectively. The increase was also due to the gain recorded as a result of unwinding interest rate swaps in first quarter 2007 of \$0.4 million and to \$0.3 million from higher interest and investment revenue.

Operating and administrative expense was \$31.2 million in 2007 compared to \$29.7 million in 2006. The increase was primarily related to \$1.9 million in a one-time charge related to the write-off of costs incurred on development projects and \$0.4 million in higher compensation costs, partially offset by lower professional and consulting fees of \$1.0 million and lower general corporate overhead.

Amortization expense for 2007 was consistent with 2006.

Corporate Outlook

The operating loss for 2008 is expected to be higher than in 2007 due primarily to the acquisition of Taylor and AltaGas growth through acquisitions and the expansion of current facilities. In 2007 Taylor recorded approximately \$8 million in corporate costs on a normalized basis. AltaGas has realized approximately \$2 million in cost savings of the total \$3.0 million identified at the time the Taylor transaction was announced. The segment's revenue will decrease as AltaGas will no longer be recording investment income from Taylor in the Corporate segment and also due to a decrease in ownership of Utility Group from 26.7 percent to 19.6 percent.

The effects of financial instruments are based on estimates relating to commodity prices and foreign exchange rates over time. The actual amounts will vary based on these drivers and management is therefore unable to predict the impact of financial instruments. However, the impact of the accounting standards is expected to be relatively low as the Trust uses financial instruments to manage exposure to commodity price fluctuations and to buy and sell gas and power with locked-in margins. The Trust does not execute financial instruments for speculative purposes.

INVESTED CAPITAL

During 2007 AltaGas acquired \$86.1 million in capital assets, long-term investments and other assets, up from \$71.5 million in 2006. The increase was due to acquiring \$68.2 million in capital assets and \$17.9 million in long-term investments and other assets, of which \$20.3 million was an increase in the fair value of Taylor units which were reported as assets available for sale and \$3.4 million was for costs related to the acquisition of Taylor, partially offset by the special distribution of Utility Group common shares valued at \$4.2 million and the elimination of \$2.1 million in loans advanced to BMWLP. The \$46.4 million in disposals of capital assets included the \$30.2 million disposition of the original cost of the oil and natural gas production assets in Energy Services and the original cost of the \$14.4 million interest in the Ikhlil Joint Venture reported in the FG&P segment.

Maintenance capital expenditures totalled \$5.7 million in 2007 compared to \$6.1 million in 2006, of which \$4.0 million in 2007 was in the FG&P segment. Of the \$56.2 million spent on growth capital in 2007 (2006 – \$62.0 million), \$23.3 million was spent in the FG&P segment, which included \$16.5 million on CBM projects consisting of the Acme plant construction and the Corbett Creek acquisition, and another \$6.5 million spent on upgrading and expanding existing FG&P facilities. In the Power Generation segment, \$13.9 million was spent on the Bear Mountain Wind project and \$6.6 million was for the new peaking generation equipment and installation costs to date. AltaGas also invested \$8.0 million in the Sarnia Airport Storage Pool project in Ontario as part of its strategy to grow its gas infrastructure and diversify geographically. Costs of \$3.4 million were incurred related to the offer to purchase the outstanding Taylor units, which was more than offset by the \$4.2 million special distribution of Utility Group shares to AltaGas unitholders. Administrative capital expenditures of \$24.2 million in 2007 were significantly higher than the \$3.4 million reported in 2006, primarily due to a \$20.3 million increase in the fair value of Taylor units which were reported as assets available for sale.

For the year ended December 31, 2007 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	29.1	5.0	22.0	9.8	2.3	68.2
Long-term investments and other assets	–	–	(0.5)	–	18.4	17.9
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals						
Capital assets	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

For the year ended December 31, 2007 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	4.0	1.7	–	–	–	5.7
Growth	23.3	3.3	21.5	9.3	(1.2)	56.2
Administrative	1.8	–	–	0.5	21.9	24.2
	29.1	5.0	21.5	9.8	20.7	86.1
Disposals	(15.9)	(0.3)	–	(30.2)	–	(46.4)
Net invested capital	13.2	4.7	21.5	(20.4)	20.7	39.7

For the year ended December 31, 2006 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	58.5	4.3	–	0.8	2.2	65.8
Long-term investments and other assets	–	–	4.3	–	1.4	5.7
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals						
Capital assets	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

For the year ended December 31, 2006 (\$ millions)	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	5.0	0.8	–	0.3	–	6.1
Growth	53.3	3.4	4.3	0.2	0.8	62.0
Administrative	0.2	0.1	–	0.3	2.8	3.4
	58.5	4.3	4.3	0.8	3.6	71.5
Disposals	(0.8)	–	–	–	–	(0.8)
Net invested capital	57.7	4.3	4.3	0.8	3.6	70.7

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates, particularly in the Power Generation segment and with respect to interest rates on debt. During 2007, the Trust had positions in the following types of derivatives:

Commodity Forward Contracts

The Trust executes gas, power, and other commodity forward contracts to manage its asset portfolio and lock in margin from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The Energy Services segment transacts primarily on this basis.

Commodity Swap Contracts

The Trust executes fixed-for-floating power price swaps to manage its power asset portfolio. A fixed-for-floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power Generation segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and whereas prices ranged from \$0.00/MWh to \$999.99/MWh in 2007, the average spot price was \$66.84/MWh for the year. AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio that management deemed optimal. The average price received for power by the Trust was \$68.59/MWh in 2007. The Trust opportunistically executes fixed-for-floating frac spread swaps to manage its NGL frac spreads.

NGL Frac Spread Hedges

The Trust executes fixed-for-floating frac spread swaps to manage its NGL frac spreads. The E&T segment's results are affected by frac spreads. In the fourth quarter of 2007, the Trust entered into NGL frac spread agreements for 1,400 Bbls/d at \$25.50/Bbl for the first quarter 2008 and for 700 Bbls/d at \$21.50/Bbl from April 1 to December 31, 2008. With the acquisition of Taylor, AltaGas has assumed frac spread hedges for an additional 1,200 Bbls/d with an average price of \$20.00/Bbl for January 1 through December 31, 2008.

Interest Rate Forward Contracts

The Trust enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate. At December 31, 2007 the Trust had interest rate swaps with varying terms to maturity of \$25.0 million. Including AltaGas' MTNs and capital leases, the rate was fixed on 100 percent of AltaGas' debt.

Foreign Exchange Forward Contracts

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts where a fixed rate is locked in against a floating rate. The Trust's foreign exchange risk was not material at December 31, 2007. The Trust has entered into a number of forward rate contracts to hedge its euro exposure as it relates to the Bear Mountain project.

LIQUIDITY AND CAPITAL RESOURCES

AltaGas expects that funds from operations in 2008 will be sufficient to meet the Trust's distributions to unitholders and the majority of its budgeted maintenance and growth capital expenditures. The balance of its budgeted growth capital and a certain amount of unbudgeted acquisitions will be financed through the Distribution Reinvestment Plan (DRIP) and existing bank lines. Should larger acquisitions require financing beyond existing sources, management is confident, based on historical success, that equity and debt capital markets could be accessed to provide additional financing. At this time AltaGas does not reasonably expect any presently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash, except that cash from operations may be impacted by the taxable component of the Trust's distribution beginning in the 2011 taxation year.

On January 10, 2008 AltaGas acquired Taylor units for the aggregate purchase price of \$598.7 million, including cash of \$256.3 million and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all of the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$11.0 million in transaction costs which was funded with bankers' acceptances through AltaGas' syndicated credit facilities.

Cash Flows (\$ millions)	2007	2006
Cash from operations	183.3	146.9
Investing activities	(63.4)	(78.5)
Financing activities	(120.6)	(66.9)
	(0.7)	1.5

Cash from Operations

Cash from operating activities reported on the Consolidated Statements of Cash Flows increased by \$36.4 million, or 25 percent, to \$183.3 million in 2007 from \$146.9 million in 2006. The increase in cash flow was primarily due to a decrease in non-cash working capital items. Accounts receivable decreased as a result of lower volumes and commodity prices, the timing of payments in the Power Generation segment, and gas storage positions that had built up in the latter half of 2006 decreasing in 2007. The decrease in working capital was partially offset by lower payables as a result of lower commodity prices and the timing of payment of capital costs.

Working Capital (\$ millions except ratio amounts)	2007	2006
Current assets	305.4	263.4
Current liabilities	286.1	239.7
Working capital	19.3	23.7
Current ratio	1.07	1.10

Investing Activities

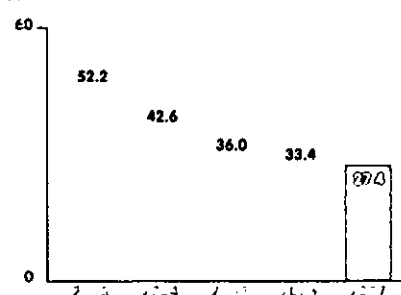
During 2007 the Trust used cash for investing activities of \$63.4 million compared to \$78.5 million in 2006. The decrease in cash used for investing activities was due to lower acquisitions of capital assets in 2007, increased customer deposits and higher proceeds on dispositions of non-core assets.

Financing Activities

Cash used for financing activities was \$120.6 million in 2007 compared to \$66.9 million used in 2006. Significant financing activities in 2007 included a reduction to debt of \$44.4 million, \$8.1 million higher distributions paid to unitholders than in 2006 and \$4.8 million lower proceeds from the DRIP as a result of the suspension of the Premium component of the DRIP.

Capital Resources

Debt as a Percent of
Total Capitalization
%



The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2007 AltaGas had total debt outstanding of \$220.7 million, down from \$265.5 million as at December 31, 2006. As of December 31, 2007 the Trust had \$200.0 million in MTNs outstanding and had access to prime loans, bankers' acceptances and letters of credit through bank lines totaling \$425.0 million. As at December 31, 2007 the Trust had drawn bank debt of \$10.0 million and letters of credit outstanding of \$64.5 million.

All of the borrowing facilities have financial tests and other covenants customary for these types of facilities, which must be met at each quarter-end. AltaGas has been in compliance with these covenants each quarter since the issuance of the facilities.

AltaGas' target debt-to-total-capitalization ratio is 40 to 45 percent. The Trust's debt-to-total-capitalization ratio as at December 31, 2007 was 27.4 percent, down from 33.4 percent at December 31, 2006. The Trust's earnings interest coverage for the rolling 12 months ended December 31, 2007 was 10.65.

The Dominion Bond Rating Service (DBRS) rates AltaGas Income Trust and the MTNs issued by AltaGas Income Trust at BBB (low). In January 2008, DBRS confirmed AltaGas' medium-term notes and stability ratings at BBB (low) and STA-3 (middle) respectively. The trend on the medium-term notes rating was changed to Stable from Positive.

Standard & Poor's Ratings Services (S&P) rates the Trust's long-term corporate credit at BBB- with a stable outlook, and the senior unsecured debt at BBB-. In December 2007 S&P affirmed AltaGas' ratings.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity of an entity to meet its financial commitment in accordance with the terms of an obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an entity's distribution stream when compared to other stability rated entities.

Credit Facilities (\$ millions)	Borrowing capacity	Drawn at December 31, 2007	Drawn at December 31, 2006
Demand operating facility	50.0	2.8	–
Letter of credit facility	75.0	61.7	63.3
Syndicated operating credit facility ⁽¹⁾	300.0	10.0	154.3
	425.0	74.5	217.6

⁽¹⁾ Extendible revolving-term credit facility that can be extended beyond the current term date of September 30, 2010 for an additional year.

At December 31, 2007 the Trust held a \$75.0 million (2006 – \$75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to \$25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. At December 31, 2007 the Trust had letters of credit of \$61.7 million (2006 – \$63.3 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of \$2.8 million (2006 – \$3.0 million) outstanding against the demand operating facility.

Contractual Obligations

(\$ millions)	Payments Due by Period				
	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt	211.7	4.7	207.0	–	–
Capital leases	12.5	1.9	3.8	3.8	3.0
Operating leases	15.9	3.9	6.8	5.2	–
Purchase commitments	150.2	34.4	115.8	–	–
Total contractual obligations	390.3	44.9	333.4	9.0	3.0

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2007 was \$10.0 million (2006 – \$11.8 million) with the balance due in monthly payments comprising principal and interest of \$0.2 million.

The Trust has long-term operating lease agreements for office space, office equipment and automotive equipment. The Trust also has purchase commitments for the development of the Bear Mountain Wind project including the purchase and installation of the wind turbines.

Other Commitments

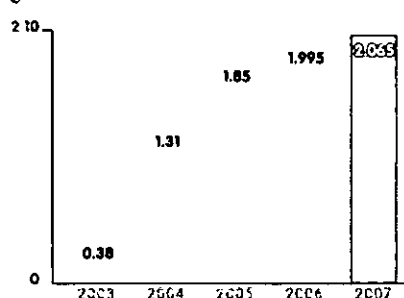
Under the terms of a 1997 long-term gas supply contract the Trust is committed to supplying natural gas at prices ranging from \$2.34/Mcf in 2007 to \$2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. One of those producers defaulted on its obligation under its gas supply contract in 1999, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

DISTRIBUTIONS

AltaGas' distributions are determined giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. AltaGas declared \$118.6 million of distributions to unitholders in 2007 compared to \$110.8 million in 2006.

The Trust suspended the Premium component of the DRIP (PDRIP) effective with the August 2007 distribution. The regular component of the DRIP remains in effect and will continue to support AltaGas' financing strategy. In the future, as conditions warrant, the Trust may consider reinstating the PDRIP based on AltaGas' capital requirements and desire to maintain an efficient capital structure. While the PDRIP is suspended, PDRIP participants will continue to receive regular cash distributions. For further information on the DRIP please visit AltaGas' website at www.altagas.ca.

**Cash Dividends/Distributions
Declared per Unit**



The Board of Directors of AltaGas General Partner Inc., delegate of the Trustee, increased its monthly cash distribution to \$0.175 per unit (\$2.10 per unit annualized) from \$0.17 per unit (\$2.04 per unit annualized) payable on September 17, 2007 to unitholders of record on August 27, 2007. This was AltaGas' fourth distribution increase since converting to a trust in May 2004. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment date or record date falls on a weekend or holiday.

In addition, a special distribution of one Utility Group common share for every 100 trust units and exchangeable units of AltaGas held on August 27, 2007 was made on September 17, 2007. The Trust distributed 577,416 shares valued at \$4.2 million.

The following table summarizes AltaGas' distribution declaration history since 2005:

(\$ per unit)	2007	2006	2005
First quarter	\$ 0.510	\$ 0.485	\$ 0.45
Second quarter	0.510	0.495	0.45
Third quarter	0.520	0.505	0.47
Fourth quarter	0.525	0.510	0.48
Distribution of shares ⁽¹⁾	0.076	-	0.54
	\$ 2.141	\$ 1.995	\$ 2.39

⁽¹⁾ On September 17, 2007, one share of Utility Group was issued for every 100 trust and exchangeable units held on August 27, 2007. On November 17, 2005, one share of Utility Group was issued for every 13.9592 trust and exchangeable units held on November 14, 2005.

Assuming a unit was held throughout 2007, for income tax purposes the Trust expects 69.73 percent of the total distributions declared in 2007 to be taxed as property income, 0.22 percent as dividend income, 0.62 percent as capital gains and 29.43 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their Trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

TRUST UNIT INFORMATION

Under the terms of the restructuring of AltaGas into an income trust effective May 1, 2004, ASI security holders exchanged their shares in ASI for Trust units and eligible security holders also received exchangeable units that are exchangeable into Trust units on a one-for-one basis. The exchangeable units are not listed for trading on an exchange.

Units Outstanding

At January 31, 2008 the Trust had 63.4 million Trust units and 2.2 million exchangeable units outstanding and a market capitalization of \$1.5 billion based on a closing trading price on January 31, 2008 of \$23.35 per Trust unit. At January 31, 2008 there were 1.3 million options outstanding and 350,967 options exercisable under the terms of the unit option plan.

CHANGES IN ACCOUNTING POLICIES

2007 Changes

Effective January 1, 2007 AltaGas adopted the revised Canadian Institute of Chartered Accountants (CICA) Handbook Section 1506. This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements.

Financial Instruments

Effective January 1, 2007 the Trust prospectively adopted the CICA Handbook; Section 1530 "Comprehensive Income"; Section 3855 "Financial Instruments – Recognition and Measurement"; Section 3865 "Hedges"; and Section 3861 "Financial Instruments – Disclosure and Presentation". The impacts of adopting the new standards are reflected in the Trust's annual results, and prior year comparative financial statements have not been restated. While the new rules resulted in changes to how the Trust accounts for its financial instruments, there were no material impacts on the Trust's current financial results. For a description of the new accounting rules and the impact on the Trust's financial statements of adopting such rules, see note 12 to the annual Consolidated Financial Statements for the year ended December 31, 2007.

Future Accounting Changes

Section 1535 "Capital Disclosures"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

Section 3031 "Inventories"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

Section 3862 "Financial Instruments – Disclosures" and Section 3863 – "Financial Instruments – Presentation"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

International Financial Reporting Standards (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian generally accepted accounting principles with IFRS over an expected five-year transition period, with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions which have been made using careful judgment. AltaGas' significant accounting policies are contained in the Notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations and asset impairment assessment. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

Amortization

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustment to the amount of amortization that the Trust recognizes from period to period.

Asset Retirement Obligations and Other Environmental Costs

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs is a critical accounting estimate because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2025 and 2035), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's Consolidated Financial Statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistent with prior periods.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guaranteed contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

RELATED PARTIES

The Trust sold \$83.4 million of natural gas to, and incurred transportation costs of \$0.5 million charged by Utility Group in 2007. The Trust also paid management fees of \$0.4 million to, and received management fees of \$29,000 from, Utility Group for administrative services in 2007. In addition, the Trust provided \$0.3 million of operating services to Utility Group.

During 2007 the Trust sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for \$9.0 million. The gain on the sale was negligible.

The Trust pays rent under a lease for office space to 2013761 Ontario Inc., which is owned by an employee. Payments of approximately \$85,000 were made in 2007 (2006 – \$80,000). The five-year lease expired in 2007 and was renewed for an additional year.

DISCLOSURE CONTROLS AND PROCEDURES

The Trust maintains disclosure controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under applicable laws is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

In accordance with Multilateral Instrument 52-109 (Certification of Disclosure in Issuers' Annual and Interim Filings), management carried out an evaluation, under the supervision and with the participation of management, including the Chairman and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that disclosure controls and procedures were effective as of December 31, 2007 to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized, and reported within the time periods specified in the Ontario Securities Commission's rules and forms.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining adequate internal controls over financial reporting. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be designed effectively can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Trust has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework to evaluate the design of internal controls over financial reporting.

At December 31, 2007 management assessed the design of the Trust's internal control over financial reporting and concluded that such internal control over financial reporting is suitably designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. The assessment also concluded that there were no material weaknesses in the design of AltaGas' internal control financial reporting that have been identified by management.

There have been no changes in design of internal control over financial reporting during the year ended December 31, 2007 that have materially affected or are reasonably likely to materially affect AltaGas' internal control over financial reporting.

SUBSEQUENT EVENTS

Acquisition of Taylor NGL Limited Partnership

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7 MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders \$11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of \$245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, \$27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was \$598.7 million, including \$256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$11.0 million in transactions costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:

(\$ millions)

Cost of 8.9% investment in Taylor originally owned by AltaGas		24.6
Purchase price for the remaining 91.1% of Taylor Units		
Cash considerations	256.3	
Units	198.9	
Estimated transaction costs	11.0	
Equity portion of Taylor convertible debentures	2.1	468.3
Total consideration		\$ 492.9

Purchase price allocation for 100% of Taylor:

(\$ millions)

Assets acquired

Current assets	30.8	
Capital assets	590.0	
Energy service arrangements, contracts and relationships	83.9	
Goodwill	108.2	
Long-term investments and other assets	4.6	817.5

Less Liabilities assumed

Current liabilities	31.2	
Long-term debt	110.2	
Convertible debentures	22.2	
Asset retirement obligations	14.4	
Future income taxes	144.0	
Future employee obligations	2.5	
Risk management	0.1	324.6
		\$ 492.9

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income. As of January 10, 2008, Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of \$256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately \$610 million compared to \$220.7 million as at December 31, 2007 and a debt-to-total capitalization ratio of approximately 45 percent.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for \$4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at \$24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

FOURTH QUARTER HIGHLIGHTS

Net income for the three months ended December 31, 2007 was \$31.8 million (\$0.55 per unit) compared to \$27.3 million (\$0.49 per unit) for the same period in 2006. Excluding a \$6.1 million non-cash tax recovery due to reduced federal tax rates enacted in fourth quarter 2007, net income for fourth quarter 2007 was \$25.7 million. Net income increased primarily due to higher hedge prices and lower costs in the Power Generation segment, lower operating and administrative costs, higher frac spreads and higher extraction volumes exposed to frac spreads. These increases were more than offset by lower throughput and operating cost recoveries in FG&P, lower Alberta spot power prices and a lower contribution from the Energy Services segment.

On a consolidated basis, net revenue for the quarter ended December 31, 2007 was \$76.4 million compared to \$84.6 million in the same quarter of 2006. Net revenue decreased in fourth quarter 2007 due to lower Alberta spot power prices, lower throughput in FG&P, and lower revenues as a result of the sale of oil and gas production assets in May 2007. The decreases were partially offset by higher hedge prices and lower costs in the Power Generation segment, higher frac spreads and higher frac spread-exposed extraction volumes.

Operating and administrative expense for fourth quarter 2007 was \$36.2 million down from \$40.1 million in the same quarter of 2006. The decrease was primarily due to lower operating costs in FG&P, lower costs as a result of the sale of the Ikhil Joint Venture and the oil and natural gas production assets, as well as lower consulting fees in part related to the compliance with securities regulations incurred in 2006. These decreases were partially offset by higher compensation and administrative costs.

Amortization expense for fourth quarter 2007 was \$11.4 million compared to \$12.5 million in the same quarter last year. The decrease was due to the disposition of oil and natural gas production assets in 2007 and a \$0.6 million write-down of goodwill on a non-core investment in fourth quarter 2006, partially offset by new and expanded FG&P facilities.

Interest expense for fourth quarter 2007 was \$2.9 million compared to \$3.3 million in the same quarter of 2006. The decrease was due to lower average debt balances of \$218.6 million compared to \$271.9 million for the same period in 2006, partially offset by higher average borrowing rates. The average borrowing rate in fourth quarter 2007 was 5.5 percent compared to 4.9 percent in fourth quarter 2006.

In fourth quarter 2007 the Trust reported an income tax recovery of \$5.8 million compared an income tax expense of \$1.4 million in the same quarter last year. Lower federal corporate income tax rates enacted in the quarter resulted in a tax recovery of \$6.1 million and was offset by higher tax expense of \$0.3 million due to higher income subject to tax.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2008 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per unit
Gathering and processing volumes ⁽¹⁾	5 Mmcfd	0.016
Gathering and processing operating margin per Mcf ⁽¹⁾	1 cent /Mcf	0.027
Alberta electricity prices ^{(1) (2)}	\$1/MWh	0.010
Natural gas liquids fractionation spread ^{(1) (3)}	\$1 per Bbl	0.011
Interest rates ⁽¹⁾	25 bps	0.004

⁽¹⁾ Includes the effects of the Taylor assets added January 10, 2008.

⁽²⁾ Based on 70 percent of PPA volumes being hedged.

⁽³⁾ Based on 55 percent of exposed volumes not hedged.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENTLY COMPLETED QUARTERS

(\$ millions)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net revenue ⁽¹⁾	76.4	88.2	80.1	79.3	84.6	82.5	72.8	79.1
Operating income ⁽¹⁾	28.9	37.5	31.2	29.0	32.0	33.7	26.0	35.0
Net income	31.8	31.4	21.1	24.6	27.3	28.8	29.9	28.6

(\$ per unit)	Q4-07	Q3-07	Q2-07	Q1-07	Q4-06	Q3-06	Q2-06	Q1-06
Net income	—	—	—	—				
Basic	0.55	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Diluted	0.55	0.54	0.37	0.43	0.49	0.52	0.54	0.52
Distributions declared ⁽²⁾	0.525	0.52	0.51	0.51	0.51	0.505	0.495	0.485

⁽¹⁾ Non-GAAP financial measure. See "Non-GAAP Financial Measures".

⁽²⁾ Excludes the special distribution issuance of one common share of Utility Group for every 100 trust and exchangeable units held on August 27, 2007, valued at \$0.076 per unit.

Identifiable trends in AltaGas' business in the past eight quarters reflect: the organization's internal growth; acquisitions; a favourable business environment including generally increasing power prices in Alberta; asset dispositions; and lower throughput in the FG&P segment.

Significant items that impacted individual quarterly earnings were as follows:

- Results in the FG&P segment are typically lower in the first quarter compared to the fourth quarter;
- In second quarter 2006 a \$6.6 million non-cash future income tax benefit was recorded as a result of a reduction in the federal and Alberta corporate income tax rates;
- In fourth quarter 2006 the Trust reported a \$0.6 million goodwill impairment and deferred \$0.8 million in revenue in the transmission business;
- In second quarter 2007 the Trust recorded a \$6.5 million future tax expense as a result of new tax legislation included in Bill C-52 which was substantially enacted by the Government of Canada. This non-cash charge to earnings relates to the temporary differences between the accounting and tax basis of AltaGas' assets and liabilities; and
- In fourth quarter 2007 a \$6.1 million non-cash future income tax benefit was recorded as a result of a reduction in the federal corporate income tax rates.

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management's and auditors' reports

Management's Responsibility for Financial Statements

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. Further, management is satisfied that the financial information contained in this annual report is consistent with that presented in the Consolidated Financial Statements. The internal controls and systems of AltaGas Income Trust (AltaGas or the Trust) are designed to provide reasonable assurance that its assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine

the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements in this report.

(signed) "David W. Cornhill"

DAVID W. CORNHILL
CHAIRMAN AND CHIEF EXECUTIVE OFFICER OF
ALTAGAS GENERAL PARTNER INC., DELEGATE OF
THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008

(signed) "Deborah S. Stein"

DEBORAH S. STEIN
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER
OF ALTAGAS GENERAL PARTNER INC., DELEGATE OF
THE TRUSTEE OF ALTAGAS INCOME TRUST

March 3, 2008

Auditors' Report

TO THE UNITHOLDERS OF ALTAGAS INCOME TRUST

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2007 and 2006 and the consolidated statements of income and accumulated earnings, comprehensive income and accumulated other comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. 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 AltaGas Income Trust 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.

(signed) "Ernst & Young LLP"

ERNST & YOUNG LLP
CHARTERED ACCOUNTANTS

February 26, 2008
Calgary, Canada

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Consolidated Balance Sheets

As at December 31

(\$ thousands)

	2007	2006
ASSETS		
Current assets		
Cash and cash equivalents	\$ 12,451	\$ 13,226
Accounts receivable	191,879	224,533
Inventory	130	61
Customer deposits	24,369	16,304
Risk management (note 12)	66,811	-
Other current assets	9,714	9,277
	305,354	263,401
Capital assets (notes 4 and 21)	682,322	677,941
Energy services arrangements, contracts and relationships (note 5)	95,716	103,330
Goodwill (note 6)	18,260	18,260
Risk management (note 12)	33,640	-
Long-term investments and other assets (note 7)	64,509	46,643
	\$ 1,199,801	\$ 1,109,575
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	\$ 177,802	\$ 200,882
Distributions payable to unitholders	10,167	9,588
Short-term debt (note 8)	655	-
Current portion of long-term debt (note 9)	1,234	1,147
Customer deposits	24,369	16,304
Deferred revenue	1,718	788
Risk management (note 12)	60,848	-
Other current liabilities	9,321	10,982
	286,114	239,691
Long-term debt (note 9)	218,845	264,340
Asset retirement obligations (note 10)	18,811	23,350
Future income taxes (note 11)	58,229	51,252
Risk management (note 12)	30,166	-
Other long-term liabilities	2,948	1,526
	615,113	580,159
Unitholders' equity (notes 13 and 14)	584,688	529,416
	\$ 1,199,801	\$ 1,109,575

Commitments (notes 8, 9, 12, 16 and 18)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

(signed) "David W. Cornhill"

DAVID W. CORNHILL
DIRECTOR

(signed) "Robert B. Hodgins"

ROBERT B. HODGINS
DIRECTOR

Consolidated Statements of Income and Accumulated Earnings

For the years ended December 31

(\$ thousands except per unit amounts and number of units)

	2007	2006
Revenue		
Operating	\$ 1,422,242	\$ 1,358,189
Unrealized gains on risk management (note 12)	1,115	-
Other	5,037	4,415
	1,428,394	1,362,604
Expenses		
Cost of sales	1,104,399	1,043,691
Operating and administrative	150,297	145,788
Amortization:		
Capital assets	39,477	38,377
Energy services arrangements, contracts and relationships	7,614	7,484
Goodwill impairment (note 6)	-	600
	1,301,787	1,235,940
Operating income	126,607	126,664
Interest expense (notes 8, 9 and 12)		
Short-term debt	491	270
Long-term debt	11,394	13,012
Income before income taxes	114,722	113,382
Income tax expense (recovery) (note 11)	5,928	(1,129)
Net income	108,794	114,511
Accumulated earnings, beginning of year	401,618	287,107
Accumulated earnings, end of year	\$ 510,412	\$ 401,618
Net income per unit (note 15)		
Basic	\$ 1.90	\$ 2.06
Diluted	\$ 1.89	\$ 2.06
Weighted average number of units outstanding (thousands) (note 14)		
Basic	57,382	55,469
Diluted	57,420	55,516

See accompanying notes to the Consolidated Financial Statements.

consolidated financial statements

Consolidated Statements of Comprehensive Income and Accumulated Other Comprehensive Income

For the year ended December 31

(\$ thousands)

2007

Net Income	\$ 108,794
Other comprehensive income, net of tax (note 12)	
Unrealized net gains on available for sale financial assets	17,902
Unrealized net gains on derivatives designated as cash flow hedges	7,051
Reclassification to net income of net loss on derivatives designated as cash flow hedges pertaining to prior periods	4,850
	29,803
Comprehensive income	\$ 138,597
Accumulated other comprehensive income, beginning of year	-
Adjustment resulting from adoption of new financial instrument accounting standards (note 2)	(2,634)
Other comprehensive income, net of tax	29,803
Accumulated other comprehensive income, end of year	\$ 27,169

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31

(\$ thousands)

	2007	2006
Cash from operations		
Net income	\$ 108,794	\$ 114,511
Items not involving cash:		
Amortization	47,091	45,861
Accretion of asset retirement obligations (note 10)	1,474	1,430
Unit-based compensation (note 14)	553	482
Future income tax expense (recovery) (note 11)	5,631	(1,181)
Gain on sale of assets	57	-
Equity income	(2,274)	(3,967)
Distributions from equity investments	1,490	2,950
Goodwill impairment (note 6)	-	600
Unrealized gains on risk management (note 12)	(1,115)	-
Other	1,199	994
Funds from operations	162,900	161,680
Asset retirement obligations settled (note 10)	(346)	(560)
Net change in non-cash working capital (note 17)	20,725	(14,260)
	183,279	146,860
Investing activities		
Increase in customer deposits	(8,065)	(933)
Decrease in note receivable	5,100	-
Acquisition of capital assets	(65,065)	(73,042)
Disposition of capital assets	9,759	509
Disposition of energy services arrangements, contracts and relationships	-	36
Acquisition of long-term investments and other assets	(5,567)	(5,032)
Disposition of long-term investments and other assets	412	-
	(63,426)	(78,462)
Financing activities		
Increase (decrease) in short-term debt	655	(2,710)
Decrease in long-term debt	(45,016)	(829)
Distributions to unitholders	(118,061)	(109,954)
Net proceeds from issuance of units (note 14)	41,794	46,636
	(120,628)	(66,857)
Change in cash and cash equivalents	(775)	1,541
Cash and cash equivalents, beginning of year	13,226	11,685
Cash and cash equivalents, end of year	\$ 12,451	\$ 13,226

See accompanying notes to the Consolidated Financial Statements.

consolidated financial statements

Notes to the Consolidated Financial Statements

(Tabular amounts in thousands of dollars unless otherwise indicated.)

1. Structure of AltaGas Income Trust

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI).

2. Summary of Significant Accounting Policies

These Consolidated Financial Statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

Basis of Presentation

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

Until second quarter 2007 AltaGas accounted for its investment in Taylor NGL Limited Partnership (Taylor) using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in Other comprehensive income (OCI) (see note 12).

Changes in Accounting Policies

Effective January 1, 2007 the Trust adopted the new CICA Handbook accounting requirements for 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". In accordance with the transitional provisions for these new standards, these policies were adopted prospectively without restatement of prior periods.

ACCOUNTING CHANGES

This section prescribes the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. The adoption of this standard did not have a material impact on the Consolidated Financial Statements of the Trust.

FINANCIAL INSTRUMENTS

All financial instruments, including derivatives, are included on the balance sheet initially at fair value. The financial assets are classified as held for trading, held to maturity, loans and receivables, or available for sale. Financial liabilities are classified as held for trading or other financial liabilities. Subsequent measurement is determined by classification.

Held for trading financial assets and liabilities are entered into with the intention of generating a profit and consist of swaps, options and forwards. These financial instruments are initially accounted for at their fair value and changes to fair value are recorded in income. Held to maturity financial assets are accounted for at their amortized cost using the effective interest method. The Trust did not have any held to maturity financial instruments at December 31, 2007. Loans and receivables are accounted for at their amortized cost using the effective interest method. The available for sale classification includes non-derivative financial assets that are designated as available for sale or are not included in the other three classifications.

Available for sale instruments are initially accounted for at their fair value and changes to fair value are recorded through OCI. Income earned from these investments is included in Revenue.

Other financial liabilities not classified as held for trading are accounted for at their amortized cost, using the effective interest method.

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded as separate derivatives and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand alone derivative and the total contract is not held for trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the expected purchase, sale or usage requirements exception, are carried on the balance sheet at fair value. The Trust used January 1, 2003 as the transition date for identifying embedded derivatives. The Trust did not identify any embedded derivatives requiring bifurcation.

Transaction costs are incremental costs that are directly attributable to the acquisition, issue or disposal of a financial instrument. Effective January 1, 2007 the Trust reclassified \$1.1 million of unamortized deferred financing costs from Other current assets and Long-term investments and other assets to Long-term debt as a result of adopting the new standards. The reclassification of transaction costs has no impact on earnings. Effective January 1, 2007 the Trust began amortizing these costs using the effective interest rate method. Previously, these costs were amortized on a straight-line basis over the life of the debt.

HEDGES

The new standard specifies the circumstances under which hedge accounting is permissible, how hedge accounting may be performed and where the impacts should be recorded. The standard introduces three specific types of hedging relationships: fair value hedges, cash flow hedges and hedges of a net investment in self-sustaining foreign operations.

As part of its asset and liability management, the Trust uses derivatives for hedging positions to reduce its exposure to commodity price and foreign exchange risk. The Trust designates certain derivatives as hedges and prepares documentation at the inception of the hedging contract. The Trust performs an assessment at inception and during the term of the contract to determine if the derivative used as a hedge is effective in offsetting the risks in the values or cash flows of the hedged item. All derivatives are initially recorded at fair value and adjusted to fair value at each reporting date.

The Trust uses cash flow hedges to reduce its exposure to fluctuations in interest rates and changes in commodity prices. The effective portion of changes in the value of cash flow hedges is recognized in Other comprehensive income. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income in the same financial category as the underlying transaction. Gains or losses from cash flow hedges that have been included in Accumulated other comprehensive income are included in net income when the underlying transaction has occurred or becomes probable of not occurring. The maximum length of time the Trust is hedging its exposure to variability in future cash flows is 10 years.

COMPREHENSIVE INCOME AND EQUITY

The Trust's financial statements include a Consolidated Statement of Comprehensive Income and Accumulated Other Comprehensive Income which consists of earnings and the effective portion of changes in unrealized gains and losses related to available for sale assets and cash flow hedges. In addition, as required by Section 3251, the Trust now presents separately in its Unitholders' equity note the changes for each of its components of Unitholders' equity. A new component, Accumulated other comprehensive income, and a one-time transition adjustment have been added to the Trust's Unitholders' equity as a result of the implementation of this new standard (see note 12).

NET EFFECT OF ACCOUNTING POLICY CHANGES

The net effect to the Trust's financial statements at January 1, 2007 resulting from the above mentioned changes in accounting policies is as follows:

Balance Sheet Account Affected

	Increase (Decrease)
Current assets – risk management	\$ 59,866
Other current assets	(451)
Non-current assets	47,942
Long-term investments and other assets	(793)
Current liabilities – risk management	69,618
Long-term debt	(1,082)
Long-term liabilities – risk management	48,359
Future income tax liability	(7,450)
Unitholders' equity – Transition amount on adoption of new accounting standards, net of tax	(247)
Unitholders' equity – Accumulated other comprehensive income, net of tax	(2,634)

The unrealized gains and losses included in the Transition amount and in Accumulated other comprehensive income were recorded net of income tax recoveries of \$4.6 million and \$2.9 million, respectively.

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Inventory

Inventory consists of materials and supplies and is valued at the lower of average cost and replacement cost.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. The corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Repairs and maintenance costs are expensed in the period incurred.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets.

Field Gathering and Processing (FG&P)

Gathering and processing assets	15 – 25 years
Other assets	1 – 5 years

Extraction and Transmission (E&T)

Extraction and transmission assets	15 – 40 years

Power Generation

Assets under capital lease	10 years

Energy Services

Energy services assets	unit of production
Other assets	1 – 5 years

Corporate

Other assets	1 – 5 years

Leases are classified as either capital or operating. Leases which transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital lease are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term liability.

Energy Services Arrangements, Contracts, Relationships and Amortization

Energy services arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18 – 49 months
Energy services relationships	15 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC Power Partnership (ASTC). ASTC is committed to purchase all of the power from the two 353-megawatt (MW) capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses thereunder are recorded on a proportionate basis. The Sundance B PPAs required a capital outlay to acquire. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the committed power is recorded when delivered.

The Genesee power purchase arrangement had the right to generating capacity at a regulated Alberta generating unit for a three-year period that ended March 31, 2006. This PPA required no capital outlay but included monthly capacity charges, and these amounts were recorded as cost of sales. Revenue from the sale of the committed power was recorded when delivered.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp. (iQ2), PremStar Energy Canada Ltd., ECNG Canada Ltd. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

Goodwill

Goodwill represents that portion of the purchase price on acquisition which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of goodwill is determined. Any excess of the carrying value of goodwill over its implied fair value is recorded as an impairment charge to income.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost and designated as available for sale. Available for sale assets are initially accounted for at their fair value with changes to fair value recorded through OCI.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the income statement.

In the E&T segment, certain assets have an indeterminate life and thus a future retirement obligation is not recognized.

Revenue Recognition

In the FG&P segment, revenue is recorded as the services are rendered. In the Power Generation and Energy Services segments, revenue is recognized at the time the product or service is delivered. Within the E&T segment, extraction revenue is recognized at the time the product or service is delivered and transmission revenue is recorded as the services are rendered. Realized gains and losses from risk management activities related to commodity prices are recognized in the related segment revenues when the related sale occurs or when the underlying financial asset or financial liability is removed from the balance sheet. Unrealized gains and losses in respect of fair value changes to the Trust's risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the reporting period in the Corporate segment.

Transaction Costs Related to Financial Instruments

Transaction costs related to the acquisition of held for trading financial assets and liabilities and the Trust's revolving operating credit facility are expensed as incurred. For financial instruments classified as other than held for trading, transaction costs attributable to the acquisition or issue of the financial asset or liability are added to the initial carrying amount of the financial instrument and recognized in earnings using the effective interest method.

Recognition Date

AltaGas uses the settlement date for transactions. Any difference in value between the trade and settlement date for third-party transactions will be recognized on the balance sheet and in Net income or in OCI as appropriate.

Effective Interest Method

The Trust uses the effective interest method to calculate the amortized cost of a financial asset or liability and to allocate the interest income or expense over the relevant period. The effective interest rate is the rate that exactly discounts the estimated cash flows associated with the instrument over the expected life of the financial instrument, or where appropriate a shorter period, to the net carrying amount of the financial asset or liability.

Unit-Based Compensation Plans

The Trust follows the fair value method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement of cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

Pension Plans and Retiree Benefits

The cost of defined benefit pension and other retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost of the benefit is the sum of the individual current service costs and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service period of the active members covered by the defined benefit pension plans is nine to 11 years. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable on income in a particular taxation year that is not paid or payable to the unitholders in such taxation year. Prior to 2007 the Trust allocated all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and met the requirements of the Income Tax Act (Canada) applicable to the Trust. Accordingly, no provision for Canadian income tax expense was made for the Trust.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense and future income tax liability. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations and non-routine transactions have been recorded at the exchange amount.

Per Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the year. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, as a result of matters that are inherently uncertain, include among others, the fair value of certain assets including long-lived assets and goodwill; recoverability of investments; litigation; environmental and asset retirement obligations; financial instruments; pensions and other post-retirement benefits; unit based compensation; and income taxes. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Future Accounting Changes**SECTION 1535 "CAPITAL DISCLOSURES"**

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Section 1535 "Capital Disclosures" requires the disclosure of qualitative and quantitative information about the Trust's objectives, policies and processes for managing capital. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3031 "INVENTORIES"

Effective for interim and annual financial statements for fiscal years beginning on or after January 1, 2008, the new CICA Handbook Section 3031 "Inventories" provides guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value. This new section is effective for the Trust beginning January 1, 2008.

SECTION 3862 "FINANCIAL INSTRUMENTS - DISCLOSURES" AND SECTION 3863 - "FINANCIAL INSTRUMENTS - PRESENTATION"

Effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2007, the new CICA Handbook Sections 3862 and 3863 will replace Section 3861 to prescribe the requirements for presentation and disclosure of financial instruments. The objective of Section 3862 is to provide users with information to evaluate the significance of the financial instruments on the entity's financial position and performance, the nature and extent of risks arising from financial instruments, and how the entity manages those risks. The provisions of Section 3863 deal with the classification of financial instruments, related interest, dividends, losses and gains, and the circumstances in which financial assets and financial liabilities are offset. These new sections are effective for the Trust beginning January 1, 2008.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

In 2006 the Accounting Standards Board (AcSB) published a new strategic plan that will significantly affect financial reporting requirements in Canada. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over a five-year transition period with adoption required effective January 1, 2011. While AltaGas has begun assessing the adoption of IFRS for 2011, the financial impact of the transition to IFRS cannot be reasonably estimated at this time.

3. Subsequent Events**Acquisition of Taylor NGL Limited Partnership**

On January 10, 2008 AltaGas Holding Limited Partnership No. 1 acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (other than the Taylor units already owned by AltaGas and its affiliates). Taylor participated in the energy business through ownership of natural gas liquids extraction plants, natural gas processing assets and two natural gas liquids pipelines. It also had an interest in a 7-MW run-of-river hydroelectric generation plant.

AltaGas offered Taylor unitholders \$11.20 in cash or 0.42 units of AltaGas per unit of Taylor, subject to maximum aggregate limits of \$245.0 million in cash and 8.0 million Trust units, including up to approximately 1.9 million exchangeable units. Prior to closing the acquisition, \$27.9 million of Taylor convertible debentures were redeemed, increasing Taylor units outstanding by 2.7 million. The aggregate purchase price was \$598.7 million, including \$256.3 million of cash and 7.7 million Trust units (including 0.2 million exchangeable units) valued at \$198.9 million for all the outstanding units not previously owned by AltaGas, assumed debt of \$132.5 million and approximately \$ 11 million in transaction costs. The value of the Trust units issued was determined based on the weighted average market price from two days preceding to two days subsequent to November 11, 2007, the date the offer had been agreed upon and announced.

The following table summarizes the total consideration and the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor:

Cost of 8.9% investment in Taylor originally owned by AltaGas		24,672
Purchase price for the remaining 91.1% of Taylor units		
Cash considerations	256,281	
Units	198,862	
Estimated transaction costs	11,000	
Equity portion of Taylor convertible debentures	2,127	468,270
Total consideration		\$ 492,942

Purchase price allocation for 100% of Taylor:

Assets acquired		
Current assets	30,739	
Capital assets	590,030	
Energy service arrangements, contracts and relationships	83,900	
Goodwill	108,191	
Long-term investments and other assets	4,640	817,500
Less Liabilities assumed		
Current liabilities	31,202	
Long-term debt	110,241	
Convertible debentures	22,171	
Asset retirement obligations	14,350	
Future income taxes	144,028	
Future employee obligations	2,542	
Risk management	24	324,558
		\$ 492,942

Until the date of acquisition, AltaGas accounted for its investment in Taylor using the cost method. As a result, the investment in Taylor was designated as available for sale and was measured at fair value with the changes in fair value recorded in OCI. As of January 10, 2008 Taylor will be included in AltaGas' Consolidated Financial Statements.

AltaGas drew on its available credit facility to finance the cash consideration of \$256.3 million for the Taylor acquisition. As of January 10, 2008, AltaGas had total debt of approximately \$610 million compared to \$220.7 million as at December 31, 2007.

Acquisition of Potential Hydroelectric Projects

On February 13, 2008 AltaGas acquired four potential run-of-river hydro projects ranging from 6.5 to 24 MW for \$4.5 million. The projects provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia. In exchange for the development assets, AltaGas issued 180,433 special warrants for AltaGas trust units valued at \$24.94 per special warrant to Plutonic Power Corporation. The special warrants automatically convert to AltaGas units on a one-for-one basis on January 1, 2010.

4. Capital Assets

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Field Gathering and Processing						
Field gathering and processing assets	\$ 569,944	\$ (148,297)	\$ 421,647	\$ 558,411	\$ (128,643)	\$ 429,768
Other assets	4,416	(2,161)	2,255	2,860	(1,402)	1,458
Extraction and Transmission						
Extraction and transmission assets	255,810	(46,078)	209,732	250,933	(38,023)	212,910
Power Generation						
Capital lease (note 9)	13,798	(4,596)	9,202	13,798	(3,216)	10,582
Power generation assets	22,013	-	22,013	-	-	-
Energy Services						
Energy services assets	9,693	(896)	8,797	30,177	(15,250)	14,927
Other assets	2,018	(156)	1,862	1,990	(385)	1,605
Corporate						
Other assets	19,230	(12,416)	6,814	16,962	(10,271)	6,691
	\$ 896,922	\$ (214,600)	\$ 682,322	\$ 875,131	\$ (197,190)	\$ 677,941

Interest capitalized on long-term capital construction projects for the year ended December 31, 2007 was \$0.8 million (December 31, 2006 – \$nil). At December 31, 2007 the Trust had spent approximately \$42.6 million (December 31, 2006 – \$14.9 million) on capital projects under construction that were not yet subject to amortization.

5. Energy Services Arrangements, Contracts and Relationships

	2007			2006		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Energy services arrangements and contracts	\$ 115,071	\$ (37,717)	\$ 77,354	\$ 115,071	\$ (31,497)	\$ 83,574
Energy services relationships	20,892	(2,530)	18,362	20,892	(1,136)	19,756
	\$ 135,963	\$ (40,247)	\$ 95,716	\$ 135,963	\$ (32,633)	\$ 103,330

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding short-term marketing contracts.

6. Goodwill

	2007	2006
Balance, beginning of year	\$ 18,260	\$ 18,860
Goodwill impairment	-	(600)
Balance, end of year	\$ 18,260	\$ 18,260

In 2006 through its annual goodwill impairment testing AltaGas determined that the fair value of an investment in a business ancillary to the FG&P segment was less than the book value and reduced the carrying value by \$0.6 million.

7. Long-Term Investments and Other Assets

	2007	2006
Units of public trusts	\$ -	\$ 375
Equity accounted investments in public entities	11,813	40,071
Cost accounted investments in public entities	44,746	-
Deferred debt costs, net of amortization	-	759
Deferred development costs	7,242	4,332
Loans receivable – BMWLP	-	700
Warrants	286	-
Other	422	406
	\$ 64,509	\$ 46,643

At December 31, 2007 the quoted market value of the holdings of publicly traded entities was approximately \$54.2 million (December 31, 2006 – \$50.0 million).

The Trust accounts for its interests in AltaGas Utility Group Inc. (Utility Group) as an equity investment.

Until second quarter 2007 AltaGas accounted for its investment in Taylor using the equity method. Effective second quarter 2007 AltaGas ceased to exercise significant influence over Taylor and began accounting for its investment in Taylor using the cost method. As a result, the investment in Taylor is designated as available for sale and is measured at fair value with the changes in fair value recorded in OCI (see note 12).

In 2006 the Trust formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation and the GreenWing Energy Development Limited Partnership (GEDLP) with GreenWing Energy Management Ltd. In 2007 the Trust acquired 100 percent ownership of BMWLP. Through BMWLP and GEDLP, the Trust invested \$3.8 million (December 31, 2006 – \$4.3 million) in the development of wind power projects. Amortization of these deferred development costs will occur based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

In 2007 AltaGas sold Cedar Energy Partnership in exchange for a \$12 million promissory note and received 1 million warrants of the purchaser, each of which will allow AltaGas to subscribe for and purchase one fully paid and non-assessable common share in the capital of the purchaser for a three-year term ending June 1, 2010. The remaining \$6.5 million of the promissory note is included in Other current assets.

8. Short-Term Debt

At December 31, 2007 the Trust held a \$50.0 million (December 31, 2006 – \$50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. At December 31, 2007 the Trust had prime loans of \$0.7 million (December 31, 2006 – \$nil) and letters of credit of \$2.8 million (December 31, 2006 – \$3.0 million) outstanding against the facility.

The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent).

9. Long-Term Debt

	2007	2006
Operating loans	\$ 10,045	\$ 154,306
Capital lease obligations	10,034	11,181
Medium-term notes	200,000	100,000
	220,079	265,487
Less current portion	1,234	1,147
	\$ 218,845	\$ 264,340

Letter of Credit Facility

At December 31, 2007 the Trust held a \$75.0 million (December 31, 2006 – \$75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2010. AltaGas may borrow up to \$25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2007 the Trust had letters of credit of \$61.7 million (December 31, 2006 – \$63.3 million) outstanding against the extendible revolving-term letter of credit facility.

Operating Loans

At December 31, 2007 the Trust held a \$300.0 million (December 31, 2006 – \$300.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw. On September 30, 2007 AltaGas negotiated the extension of the maturity date of this facility to September 30, 2010. On December 14, 2007 AltaGas negotiated minor amendments to the facility in order to facilitate the closing of the Taylor acquisition.

At December 31, 2007 the Trust had drawn \$10.0 million (December 31, 2006 – \$154.3 million) against the facility. The prime lending rate at December 31, 2007 was 6.0 percent (December 31, 2006 – 6.0 percent). The average rate on the Trust's bankers' acceptances at December 31, 2007 was 5.2 percent (December 31, 2006 – 5.0 percent).

Medium-Term Notes

On April 29, 2005 AltaGas filed a Universal Shelf Prospectus pursuant to which the Trust may issue up to an aggregate of \$500.0 million of trust units and debt securities over a 25-month period. AltaGas filed a prospectus supplement on August 23, 2005 establishing AltaGas' medium-term note (MTN) program. On August 30, 2005 \$100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually. The proceeds of the issue were used to repay bank debt. On January 19, 2007 AltaGas issued a further \$100.0 million of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012. The net proceeds were used to pay down existing bank indebtedness and for general corporate purposes.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease for 25 MW of gas-fired power peaking capacity with an option to extend the term for an additional 15 years. The lease has payment commitments over the next five years as follows:

2008	\$ 1,878
2009	1,878
2010	1,878
2011	1,878
2012	1,878
Thereafter	3,136
	12,526
Less imputed interest at 6.85%	2,492
Present value of minimum lease payments	10,034
Less current portion	1,234
	\$ 8,800

Interest expense on capital leases was \$0.7 million in 2007 (December 31, 2006 – \$0.8 million).

10. Asset Retirement Obligations

	2007	2006
Balance, beginning of year	\$ 23,350	\$ 16,982
New obligations	423	696
Obligations settled	(346)	(560)
Obligations disposed	(4,006)	—
Revision in estimated cash flow	(2,084)	4,802
Accretion expense	1,474	1,430
Balance, end of year	\$ 18,811	\$ 23,350

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2007 was \$52.4 million (December 31, 2006 – \$57.0 million). The asset retirement obligations have been recorded in the financial statements at estimated values discounted at rates between 5.6 percent and 8.3 percent and are expected to be incurred between 2010 and 2040. The majority of the costs are expected to be incurred between 2025 and 2035. No assets have been legally restricted for settlement of the estimated liability.

11. Income Taxes***Taxation of the Trust***

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On June 12, 2007 the Specified Investment Flow-through (SIFT) tax included in the Government of Canada's Bill C-52 received Third Reading and on June 22, 2007 it received Royal Assent, creating a new 31.5 percent tax to be applied to distributions from certain income trusts and partnerships, including AltaGas, effective January 1, 2011. With the rate of reduction enacted on December 14, 2007 the new tax is to be applied to distributions at the tax rates of 29.5 percent and 28.0 percent effective January 1, 2011 and 2012 respectively.

Based on the amount of the Trust's temporary differences that are anticipated to reverse after January 1, 2011, the Trust has recorded a future income tax expense of \$5.4 million (including \$0.1 million in respect of financial instruments) and a future income tax liability in the same amount for the year ended December 31, 2007. This non-cash expense relates to temporary differences between the accounting and tax basis of AltaGas' assets and liabilities and has no immediate impact on cash flows. A tax rate of nil was applied to any temporary differences reversing before 2011.

The anticipated amount and timing of reversals of temporary differences will be dependent on the Trust's actual results, distributions and actual acquisition and disposition of assets and liabilities. As a result, a change in estimates or assumptions could materially affect the estimate of the future tax liability.

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

	2007	2006
Income before taxes – consolidated	\$ 114,722	\$ 113,382
Financial instruments – net	(1,115)	-
Income before financial instruments and taxes	113,607	113,382
Income from AltaGas Income Trust distributed to unitholders	(92,544)	(92,385)
Income before income taxes – operating subsidiaries	21,063	20,997
Statutory income tax rate (%)	32.12	34.49
Expected taxes at statutory rates	6,765	7,242
Add (deduct) the tax effect of:		
SIFT tax	5,365	-
Financial instruments	1,561	-
Resource allowance	-	(1,048)
Rate reductions applied to future income tax liabilities	(7,256)	(7,822)
Permanent differences between accounting and tax bases of assets and liabilities	294	166
Non-taxable portion of capital gains on disposition of assets and investments	(1,634)	-
Other	833	333
Income tax provision (recovery)		
Current	297	7
Future	266	(1,136)
Future SIFT	5,365	-
	\$ 5,928	\$ (1,129)
Effective income tax rate (%)	5.17	(1.00)

AltaGas' income taxes are calculated according to government tax laws and regulations which result in different values for certain assets and liabilities for income tax purposes than for financial statement purposes. The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between tax values and book carrying values on the operating subsidiaries' balance sheets at substantively enacted tax rates. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements. In the case of AltaGas, these future income taxes are not expected to result in cash taxes being paid due to the expectation of continued future intercompany interest deductions at the operating subsidiary level.

As at December 31, future income taxes were composed of the following:

	2007	2006
Capital assets	\$ 31,101	\$ 14,448
Deferred debt charges	53	(26)
Unit issue costs	(635)	(1,209)
Partnerships	26,878	41,522
Deferred compensation	(2,092)	(3,408)
Financial instruments	2,973	-
Other	(49)	(75)
	\$ 58,229	\$ 51,252

12. Financial Instruments and Financial Risk Management

In the course of normal operations the Trust purchases and sells natural gas, natural gas liquids and power commodities and issues short and long-term debt. The Trust uses derivative instruments to reduce exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates that arise from these activities. The Trust does not make use of derivative instruments for speculative purposes.

At December 31, 2007 all derivatives, other than those that meet the expected purchase, sale or usage requirements exception, were carried on the balance sheet at fair value. The fair value of power and natural gas derivatives was calculated using estimated forward prices for the relevant period. The calculation of fair value of the interest rate derivatives used quoted market rates.

At December 31, 2007 the fair value of the Trust's assets and liabilities was as follows:

Summary of Fair Values	Current	Long-term	Total
Financial assets			
Held for trading	\$ 54,928	\$ 28,272	\$ 83,200
Available for sale	-	44,746	44,746
Loans and receivables	208,581	-	208,581
	263,509	73,018	336,527
Cash flow hedges	11,883	5,368	17,251
	\$ 275,392	\$ 78,386	\$ 353,778
Financial liabilities			
Held for trading	\$ 56,720	\$ 30,079	\$ 86,799
Other financial liabilities	168,479	213,608	382,087
	225,199	243,687	468,886
Cash flow hedges	4,128	87	4,215
	\$ 229,327	\$ 243,774	\$ 473,101

Unrealized Income

The impact on net income in 2007 from the adoption of the new financial instruments standards resulted in a \$1.1 million unrealized gain.

Other Comprehensive Income

As a part of its hedging program, the Trust uses certain derivative financial instruments to manage risks. An after-tax unrealized loss of \$4.8 million was reclassified to net income. Of the \$27.2 million gain deferred in Accumulated other comprehensive income (AOCI) at December 31, 2007, a \$5.4 million gain is expected to be reclassified to net income in the next 12 months.

The available for sale assets included in the balance sheet caption, Long-term investments and other assets are recognized at fair value, net of tax, in OCI.

Effective January 1, 2007 the Trust began offsetting long-term debt transaction costs against the associated debt and began amortizing these costs using the effective interest rate method. Previously these costs were amortized on a straight-line basis over the life of the debt instrument to which they pertained. There was no material effect on the Trust's financial statements as a result of this change in policy. The effective interest rate for the medium-term notes issued in 2005 and 2007 was 4.54 percent and 5.11 percent, respectively.

Commodity Price Risk Management

NATURAL GAS

The Trust purchases and sells natural gas to its customers. The fixed-price and market-price contracts for both the purchase and sale of natural gas extend to 2012.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per GJ) ⁽¹⁾	Period (months)	Notional volume (GJ)		Fair value
			Sales	Purchases	
Commodity forward	\$2.16 to \$10.37	1 – 55	105,375,003	–	\$ (17,775)
Commodity forward	\$2.16 to \$10.37	1 – 55	–	105,375,003	\$ 14,754

⁽¹⁾ Certain of the contracts are indexed and as such a price range is not provided.

In 2007 an unrealized gain of \$2.0 million was recognized from the Trust's natural gas risk management activities.

NATURAL GAS LIQUIDS

The Trust entered into a series of swaps to lock in a portion of the margin exposed to natural gas liquids (NGL) frac spread.

At December 31, 2007 the Trust had the following contracts outstanding:

Product	Fixed price	Period (months)	Notional volume		Fair value
			Sales	Purchases	
Propane	\$1.2825 to 1.4725 US/gallon	1 – 12	9,677,178 gallon	–	\$ (1,156)
Normal butane	\$1.4950 to 1.7000 US/gallon	1 – 12	2,612,064 gallon	–	(685)
WTI	\$83.20 to 89.10 US/Bbl	1 – 12	27,489 Bbls	–	(143)
Natural gas	\$6.455 to 6.550/GJ	1 – 12	–	1,382,591 GJ	\$ 159

In 2007 the Trust recognized an unrealized loss of \$0.6 million from the Trust's NGL risk management activities.

POWER

Under the power purchase arrangements AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at market prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. Certain contracts met the expected purchase, sale or usage requirements exception and have not been included in risk management assets or liabilities. At December 31, 2007 the Trust had no intention to terminate any contracts prior to maturity.

At December 31, 2007 the Trust had the following contracts outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair value
			Sales	Purchases	
Commodity forward	\$79.00 to \$80.60	1 – 3	2,160	–	\$ (28)
Commodity forward	\$63.25 to \$68.00	1 – 3	–	2,160	\$ 31

The Trust's power risk management activities from financial contracts not included in the hedging program had an unrealized loss of \$40,248.

At December 31, 2007 the Trust had the following commodity swaps and collars outstanding:

Derivative instruments	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair value
			Sales	Purchases	
Swaps and collars	\$65.00 to \$88.00	1 – 24	1,626,624	–	\$ 10,932
Swaps and collars	\$56.50 to \$56.50	1 – 120	–	263,016	\$ 3,339

At December 31, 2007 the Trust had the following heat rate hedges outstanding:

Derivative instruments	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh)		Fair value
			Sales	Purchases	
Natural gas (per GJ)	\$6.08 to \$6.17	1	–	79,050	\$ 17,968
Power (per MWh)	\$89.00 to \$138.00	1	6,510	–	\$ 170,019

In 2007 an unrealized gain of \$0.2 million was recognized from the Trust's heat rate hedging activities.

Foreign Exchange Risk Management

To manage the risk of fluctuating cash flows due to variations in foreign exchange rates, the Trust enters into foreign exchange forward contracts. For 2007 the Trust's foreign exchange risk management activities had an unrealized loss of \$0.7 million.

Interest Rate Risk Management

To hedge against the effect of future interest rate movements, the Trust enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities. In January 2007 the Trust unwound certain of these interest rate swaps as a result of the issue of \$100 million of medium-term notes and recorded a gain of \$0.4 million. In the third quarter the Trust terminated the hedge relationship on certain swap agreements resulting in an immaterial unrealized gain. The remaining interest rate swaps have an average remaining term of 2 to 15 months and a weighted average interest rate of 3.56 percent. The Trust's interest rate risk management activities resulted in an unrealized gain of \$0.2 million and fair market value position of \$0.2 million at December 31, 2007.

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a derivative in which the Trust has an unrealized gain fails to perform according to the terms of the contract.

Credit exposure is minimized by entering into transactions with creditworthy counterparties in accordance with established credit policies and practices. At December 31, 2007 AltaGas did not have a significant concentration of credit risk with any single counterparty to financial instruments.

13. Unitholders' Equity

	2007	2006
Unitholders' capital (note 14)	\$ 505,544	\$ 463,750
Contributed surplus	3,875	3,322
Accumulated earnings	510,412	401,618
Accumulated dividends	(41,114)	(41,114)
Accumulated unitholders' distributions declared ⁽¹⁾	(391,103)	(272,464)
Distributions of common shares of Utility Group	(29,848)	(25,696)
Transition adjustment resulting from adopting new financial instruments accounting standards	(247)	–
Accumulated other comprehensive income	27,169	–
	\$ 584,688	\$ 529,416

⁽¹⁾ Accumulated unitholders' distributions paid by the Trust as at December 31, 2007 were \$380.9 million (as at December 31, 2006 – \$262.9 million).

In 2007 the holders of trust units of the Trust and holders of exchangeable partnership units of AltaGas Holding Limited Partnership No. 1 received one common share of Utility Group for every 100 trust or exchangeable units held on August 27, 2007. As part of the distribution plan, any unitholder allocated fewer than 50 common shares of Utility Group received cash. The number of common shares of Utility Group distributed to unitholders was 577,416, which reduced unitholders equity by \$4.2 million. This distribution resulted in a 27 percent reduction of the Trust's interest in Utility Group to 19.6 percent.

14. Unitholders' Capital

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange is at the option of the unitholder at anytime, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. After May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2005	52,505,514	\$ 404,854
Units issued for cash on exercise of options	9,150	127
Units issued under DRIP ⁽¹⁾	1,745,630	46,509
Units issued for exchangeable units	53,258	305
December 31, 2006	54,313,552	451,795

Exchangeable Units Issued and Outstanding:

December 31, 2005 issued by AltaGas LP #1	2,142,072	12,260
AltaGas LP #1 units redeemed for trust units	(53,258)	(305)
December 31, 2006	2,088,814	11,955
Issued and outstanding at December 31, 2006	56,402,366	\$ 463,750

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2006	54,313,552	\$ 451,795
Units issued for cash on exercise of options	3,400	68
Units issued under DRIP ⁽¹⁾	1,692,128	41,726
Units issued for exchangeable units	48,358	277
December 31, 2007	56,057,438	493,866

Exchangeable Units Issued and Outstanding:

December 31, 2006 issued by AltaGas LP #1	2,088,814	11,955
AltaGas LP #1 units redeemed for trust units	(48,358)	(277)
December 31, 2007	2,040,456	11,678
Issued and outstanding at December 31, 2007	58,097,894	\$ 505,544

⁽¹⁾ Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan.

The Trust has an employee unit option plan under which both employees and directors are eligible to receive grants. At December 31, 2007, 10 percent of units outstanding were reserved for issuance under the plan. To December 31, 2007 options granted under the plan generally had a term of 10 years to expiry and vested no longer than over a four-year period.

At December 31, 2007 outstanding options were exercisable at various dates to the year 2017 (December 31, 2006 – 2016). Options outstanding under the plan have a weighted average exercise price of \$26.36 (December 31, 2006 – \$27.23) and a weighted average remaining term of 8.76 years (December 31, 2006 – 9.23 years). As at December 31, 2007 the unexpensed fair value of unit option compensation cost associated with future periods was \$0.7 million (December 31, 2006 – \$0.9 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding			
	2007		2006	
	Number of options	Exercise price ⁽¹⁾	Number of options	Exercise price ⁽¹⁾
Unit options outstanding, beginning of year	923,550	\$ 27.23	359,200	\$ 24.53
Granted	548,500	25.31	636,500	28.60
Exercised	(3,400)	20.06	(9,150)	13.93
Cancelled	(158,250)	27.94	(63,000)	27.53
Unit options outstanding, end of year	1,310,400	\$ 26.36	923,550	\$ 27.23
Unit options exercisable, end of year	331,425	\$ 25.50	106,513	\$ 20.48

⁽¹⁾ Weighted average.

A summary of the plan as at December 31, 2007:

	Options outstanding			Options exercisable	
	Number outstanding ⁽¹⁾	Exercise price ⁽²⁾	Remaining contractual life ⁽³⁾	Number exercisable ⁽¹⁾	Exercise price ⁽²⁾
\$5.00 – \$7.00	9,000	\$ 6.10	2.45	9,000	\$ 6.10
\$7.01 – \$15.50	28,500	10.26	5.15	28,500	10.26
\$15.51 – \$25.08	416,400	24.77	9.23	54,300	24.16
\$25.09 – \$29.50	856,500	27.86	8.72	239,625	28.35
	1,310,400	\$ 26.36	8.76	331,425	\$ 25.50

⁽¹⁾ As at December 31, 2007.

⁽²⁾ Weighted average.

⁽³⁾ Weighted average number of years.

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted-average assumptions for grants as follows:

	2007	2006
Risk-free interest rate (%)	3.29	4.36
Expected lives (years)	10	10
Expected volatility (%)	21.71	20.89
Annual distribution per unit (\$)	2.04	1.981

Units Outstanding ⁽¹⁾	2007	2006
Number of units – basic ⁽²⁾	57,382,209	55,468,969
Dilutive stock options	37,632	47,216
Number of units – diluted ⁽²⁾	57,419,841	55,516,185

⁽¹⁾ Includes exchangeable units.

⁽²⁾ Weighted average.

In 2004 AltaGas implemented a unit-based compensation plan which awards phantom units to certain employees. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2007 in respect of this plan was \$5.1 million (December 31, 2006 – \$6.7 million). As at December 31, 2007 the unexpensed fair value of unit-based compensation costs associated with future periods was \$14.2 million (December 31, 2006 – \$9.9 million).

15. Income Per Unit

The following table summarizes the computation of net income per unit:

	2007	2006
Numerator:		
Numerator for basic income per unit	\$ 108,794	\$ 114,511
Numerator for basic and diluted income per unit	\$ 108,794	\$ 114,511
Denominator:		
Weighted-average number of units	57,382	55,469
Dilutive unit options	38	47
Denominator for diluted income per unit	57,420	55,516
Basic income per unit	\$ 1.90	\$ 2.06
Diluted income per unit	\$ 1.89	\$ 2.06

16. Commitments

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment are estimated as follows:

2008	\$ 3,887
2009	3,606
2010	3,181
2011	2,798
2012	2,499
	\$ 15,971

Under the terms of a 1997 long-term gas supply contract, the Trust is committed to supply natural gas for prices ranging from \$2.34/Mcf in 2007 to \$2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. In 1999, one of those producers defaulted on its obligation under its gas supply contract, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In December 2006 the Trust entered into a fixed-price contract with a third-party supplier to fix the price of the gas supply related to the commitment until its expiry in 2009.

In 1999 the Trust acquired a right to purchase natural gas from specific reserves for \$0.05/Mcf for the life of the reserves. The production from these reserves was 1,039 Mcf/d in 2007 (2006 – 1,321 Mcf/d).

In 2007 AltaGas entered into a supply and installation agreement with Enercon GmbH to supply and install wind turbines for the Bear Mountain Wind project. The Trust has an obligation to pay approximately \$144 million before the supply and installation is complete. The Trust has also entered into other supply agreements to pay approximately \$6 million for equipment and construction costs associated with the Bear Mountain Wind project.

17. Net Change in Non-Cash Working Capital

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

	2007	2006
Accounts receivable	\$ 32,654	\$ (3,849)
Inventory	(69)	34
Other current assets	6,065	(4,856)
Accounts payable and accrued liabilities	(23,080)	(14,719)
Customer deposits	8,065	933
Deferred revenue	930	788
Other current liabilities	(1,661)	209
	22,904	(21,460)
Less decrease (increase) in capital costs payable	(2,179)	7,200
Net change in non-cash working capital related to operations	\$ 20,725	\$ (14,260)

The following cash payments have been included in the determination of earnings:

	2007	2006
Interest paid	\$ 12,078	\$ 13,521
Income taxes paid	\$ 181	\$ 62

18. Pension Plans and Retiree Benefits

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all regular employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was \$1.4 million for the year ended December 31, 2007 (December 31, 2006 – \$1.3 million).

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Effective January 1, 2005 the plan was amended in respect of certain employees who transferred employment from AltaGas Utilities Inc., a then wholly owned subsidiary to the Trust during most of 2005. Assets and liabilities were transferred to Parts III and IV of the Salaried Employees' Pension Plan for three such employees during 2006.

Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2007 and 2006 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 based upon a report dated March 29, 2006. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was \$1.9 million (December 31, 2006 – \$1.9 million). At December 31, 2007, the plan had an accrued benefit liability recognized in the financial statements of \$0.3 million (December 31, 2006 – \$0.3 million).

For the year ended December 31, 2007, the net pension cost was a recovery of \$15,000 (December 31, 2006 – recovery of \$11,000).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan which provides defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. As at December 31, 2007 the accrued benefit obligation of the Trust for this plan was \$3.0 million (December 31, 2006 – \$2.1 million). At December 31, 2007 the plan had an accrued benefit liability recognized in the financial statements of \$1.9 million (December 31, 2006 – \$1.0 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a Retirement Compensation Arrangement Trust account.

For the year ended December 31, 2007 the net pension expense was \$1.0 million (December 31, 2006 – \$0.8 million).

The following table summarizes the details of the defined benefit plans:

	2007	2006
Accrued benefit obligation		
Balance, beginning of year	\$ 4,079	\$ 2,987
Net transfer in	–	165
Actuarial loss (gain)	(73)	96
Current service cost	738	657
Interest cost	240	174
Benefits paid	(83)	–
Balance, end of year	4,901	4,079
Plan assets		
Fair value, beginning of year	1,729	1,409
Net transfers in	–	164
Actual return (loss) on plan assets	(71)	144
Employer contributions	11	12
Benefits paid	(83)	–
Fair value, end of year	1,586	1,729
Funded deficit	(3,315)	(2,350)
Unamortized past service costs	778	855
Unamortized net actuarial loss	330	227
Accrued benefit asset (liability) recognized in the financial statements	\$ (2,207)	\$ (1,268)

	2007	2006
Significant actuarial assumptions used as at December 31		
Discount rate (%)	5.50	5.25 – 5.50
Expected long-term rate of return on plan assets (%)	6.00 – 6.75	6.00 – 6.75
Rate of compensation increase (%)	3.50 – 4.00	3.50 – 4.00
Average remaining service life of active employees (years)	9 – 11	9 – 12
Net benefit plan expense for the year		
Current service cost and expenses	\$ 739	\$ 657
Interest cost	240	174
Actual loss (return) on plan assets	71	(144)
Actuarial loss (gain)	(73)	96
Costs arising in the year	977	783
Differences between costs arising in the year and costs recognized in the year in respect of:		
Return on plan assets	(188)	49
Actuarial gains (loss)	84	(87)
Past service costs	77	77
Net periodic benefit plan costs recognized	\$ 950	\$ 822

19. Related Party Transactions

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts and are as follows:

	2007	2006
Fees for administration, management and other services paid by:		
Utility Group to the Trust	\$ 29	\$ 30
The Trust to Utility Group	\$ 445	\$ 1,001
Natural gas sales by the Trust to Utility Group subsidiaries	\$ 83,370	\$ 84,046
Fees for operating services paid by Utility Group subsidiaries	\$ 341	\$ 469
Transportation services provided by Utility Group subsidiaries	\$ 477	\$ 560
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	\$ 85	\$ 83

The resulting amounts due from and to related parties are non-interest bearing and are related to transactions in the normal course of business.

Included in accounts receivable at December 31, 2007 was \$13.5 million (December 31, 2006 – \$13.8 million) due to the Trust from related parties.

Included in accounts payable at December 31, 2007 is \$50,000 (December 31, 2006 – \$0.7 million) due from the Trust to related parties.

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhlil Joint Venture to Utility Group for \$9.0 million to execute the divestiture of non-core production assets.

20. Joint Ventures

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	2007	2006
Proportionate share of operating income		
Revenues	\$ 201,124	\$ 234,243
Expenses	131,220	156,649
	\$ 69,904	\$ 77,594
Proportionate share of net assets		
Current assets	\$ 33,135	\$ 44,386
Capital assets	91,238	93,917
Energy services arrangements, contracts and relationships	75,483	81,292
Long-term investments and other assets	3,643	4,637
Current liabilities	(32,780)	(43,129)
	\$ 170,719	\$ 181,103
Proportionate share of cash flows		
Operating activities	\$ 79,959	\$ 83,367
Investing activities	(571)	(57,826)
Financing activities	(79,388)	(25,541)
	\$ -	\$ -

21. Disposition on Sale of Capital Assets

During 2007 AltaGas sold its 33.3335 percent interest in the Ikhil Joint Venture to Utility Group for cash, effective July 31, 2007 at the exchange amount of \$9.0 million. The gain on the sale was negligible. In 2007 AltaGas recorded a one-time gain of \$1.5 million from the sale of oil and natural gas production assets for non-monetary consideration totaling \$11.9 million including a promissory note of \$11.6 million. The disposition also resulted in the reduction in the asset retirement obligation by \$3.7 million.

22. Segmented Information

AltaGas is an integrated energy Trust with a portfolio of assets and services used to move energy from the source to the end-user. Transactions among the reporting segments are recorded at fair value. The following describes the Trust's five reporting segments:

- Field Gathering and Processing** – natural gas gathering lines and processing facilities;
- Extraction and Transmission** – ethane and natural gas liquids extraction plants and natural gas and condensate transmission pipelines;
- Power Generation** – coal-fired and gas-fired power output under power purchase arrangements and other agreements;
- Energy Services** – energy management and gas services for natural gas and electricity; and
- Corporate** – the costs of providing corporate services and general corporate overhead, investments in public and private entities, corporate assets and the effects of changes in the fair value of risk management assets and liabilities.

The following tables show the breakdown by segment:

For the year ended December 31, 2007	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	\$ 135,105	\$ 142,938	\$ 182,535	\$ 1,022,506	\$ 5,037	\$ (60,842)	\$ 1,427,279
Unrealized gains (losses) on risk management	-	-	-	-	1,115	-	1,115
Cost of sales	(7,655)	(75,495)	(78,373)	(1,001,599)	-	58,723	(1,104,399)
Operating and administrative	(83,344)	(20,300)	(2,035)	(15,576)	(31,161)	2,119	(150,297)
Amortization	(25,901)	(8,055)	(7,488)	(3,307)	(2,340)	-	(47,091)
Operating income (loss)	\$ 18,205	\$ 39,088	\$ 94,639	\$ 2,024	\$ (27,349)	-	\$ 126,607
Operating income (loss) before unrealized gains (losses) on risk management	\$ 18,205	\$ 39,088	\$ 94,639	\$ 2,024	\$ (28,464)	-	\$ 125,492

Net additions (reductions) to:

Capital assets	\$ 13,213	\$ 4,672	\$ 22,013	\$ (20,457)	\$ 2,349	-	\$ 21,790
Long-term investments and other assets	-	-	\$ (530)	-	\$ 18,396	-	\$ 17,866
Goodwill	\$ 215	\$ 18,045	-	-	-	-	\$ 18,260
Segment assets	\$ 507,876	\$ 241,198	\$ 151,401	\$ 124,702	\$ 174,624	-	\$ 1,199,801

For the year ended December 31, 2006	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	\$ 139,016	\$ 149,143	\$ 199,344	\$ 948,939	\$ 4,415	\$ (78,253)	\$ 1,362,604
Cost of sales	(9,381)	(85,888)	(99,761)	(924,249)	-	75,588	(1,043,691)
Operating and administrative	(80,068)	(20,305)	(1,332)	(17,060)	(29,688)	2,665	(145,788)
Amortization	(23,579)	(7,733)	(7,382)	(4,848)	(2,319)	-	(45,861)
Goodwill impairment	(600)	-	-	-	-	-	(600)
Operating income (loss)	\$ 25,388	\$ 35,217	\$ 90,869	\$ 2,782	\$ (27,592)	-	\$ 126,664
Operating income (loss) before unrealized gains (losses) on risk management	\$ 25,388	\$ 35,217	\$ 90,869	\$ 2,782	\$ (27,592)	-	\$ 126,664

Net additions (reductions) to:

Capital assets	\$ 62,295	\$ 4,319	\$ (28)	\$ 1,652	\$ 2,270	-	\$ 70,508
Energy service arrangements, contracts and relationships	-	\$ -	-	\$ (36)	-	-	\$ (36)
Long-term investments and other assets	-	\$ -	\$ 4,332	-	\$ 1,390	-	\$ 5,722
Goodwill	\$ 215	\$ 18,045	-	-	-	-	\$ 18,260
Segment assets	\$ 528,636	\$ 258,480	\$ 140,427	\$ 131,907	\$ 50,125	-	\$ 1,109,575

23. Comparative Figures

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

Form 51-102F4
BUSINESS ACQUISITION REPORT

Item 1 Identity of Company

1.1 Name and Address of Company

AltaGas Income Trust
1700, 355 4th Avenue, SW
Calgary, AB T2P 0J1

1.2 Executive Officer

The name of the executive officer of AltaGas Income Trust who is knowledgeable about the significant acquisition and this business Acquisition Report is:

Debbie Stein, Vice President Finance and Chief Financial Officer
AltaGas Income Trust
1700, 355 4th Avenue, SW
Calgary, AB T2P 0J1
Tel: 1-403-691-7575

Item 2 Details of Acquisition

2.1 Nature of Business Acquired

On January 10, 2008, AltaGas Income Trust (the Trust or AltaGas) through its indirect subsidiary, AltaGas Holding Limited Partnership No. 1, acquired the outstanding units of Taylor NGL Limited Partnership (Taylor).

Taylor participates in three business lines within the midstream natural gas business: natural gas processing; natural gas liquids (NGL) extraction, and NGL by-product transportation. Taylor owns and operates the Harmattan Complex, which includes a natural gas processing facility, a deep cut NGL extraction facility and NGL fractionation and terminalling facilities. Taylor also owns the RET Complex, which is a natural gas processing facility that provides services to natural gas producers. Both complexes are located in Alberta. In addition, Taylor owns 50 percent of and operates the Joffre Extraction Plant in Alberta, and has NGL extraction ownership of 56.7 percent and fractionation and terminalling ownership of 100 percent in the Younger Extraction Plant in British Columbia. Taylor also owns two NGL pipelines: the Ethylene Delivery System and the Joffre Feedstock Pipeline, both of which move NGL between Joffre, Alberta and Fort Saskatchewan, Alberta. In addition to these business lines Taylor has an interest in a run-of-river power generation facility located in British Columbia and two run of river hydro projects that are currently under development with energy purchase arrangements with BC Hydro.

2.2 Date of Acquisition

The date of completion of the acquisition was January 10, 2008.

2.3 Consideration

The total consideration in respect of the acquisition was \$625.5 million consisting of \$256.3 million in cash, 7.7 million Trust units valued at a deemed price of \$25.77 per unit for a total of \$198.9 million (including 0.2 million exchangeable units), assumed debt of \$132.5 million, approximately \$11.0 million in transaction costs, \$26.8 million related to units previously owned by AltaGas and the equity portion of the Taylor convertible debentures.

The cash consideration has been funded through existing credit facilities. The Trust assumed Taylor's debt of \$132.5 million which is comprised of \$110.3 million drawn on a revolving credit facility and \$22.2 million in convertible debentures.

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2.4 Effect on Financial Position

The Trust, including its subsidiaries, has no plans or proposals for material changes in its business affairs or the affairs of the acquired business which may have a significant effect on the results of operations and financial position of the Trust. The newly acquired assets are low-risk, long-life and complementary to AltaGas' existing gas and power infrastructure.

2.5 Prior Valuations

Not Applicable

2.6 Parties to Transaction

The acquisition transaction was with the unitholders of Taylor NGL Limited Partnership in which AltaGas Income Trust owned approximately 8.9 percent prior to the transaction completed on January 10, 2008.

2.7 Date of Report

March 3, 2008

Item 3 Financial Statements

The following schedules are attached hereto:

The unaudited pro forma consolidated balance sheet of the Trust as at December 31, 2007 and the unaudited pro forma combined statement of income of the Trust for the three months ended and year ended December 31, 2007 together with the compilation report thereon;

The unaudited consolidated statements of income (loss) and comprehensive income (loss) and deficit and consolidated statements of cash flows of Taylor NGL Limited Partnership for the three months ended December 31, 2007 and 2006 thereon; and

The audited financial statements of Taylor NGL Limited Partnership as at and for the years ended December 31, 2007 and 2006, together with the Auditors' Report thereon.

FINANCIAL STATEMENTS INDEX

	<u>Page</u>
Unaudited Pro Forma Consolidated Financial Statements of AltaGas Income Trust as at and for the three-months ended and the year ended December 31, 2007.....	4
Unaudited Taylor NGL Limited Partnership statement of income (loss) and Comprehensive Income (loss) and deficit and statement of cash flows as of the three months ending December 31, 2007 and 2006.....	11
Audited Financial Statements and notes thereto and the report of the auditors thereon of Taylor NGL Limited Partnership for the year ended December 31, 2007 with comparative financial statements for 2006.....	14

ALTAGAS INCOME TRUST

***PRO FORMA
CONSOLIDATED BALANCE SHEET
AND
CONSOLIDATED STATEMENT OF INCOME***

UNAUDITED

For the periods ending December 31, 2007

AltaGas Income Trust

Unaudited Pro Forma Consolidated Balance Sheet

(Thousands of dollars)

As at December 31, 2007

	AltaGas	Taylor	Pro forma Adjustments (note 2)	Pro forma Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	12,451	2,224	(4,806)	9,869
Accounts receivable	191,879	30,153	1,895	223,927
Inventory	130	-	-	130
Customer deposits	24,369	-	-	24,369
Risk management	66,811	-	-	66,811
Other	9,714	1,225	48	10,987
Total current assets	305,354	33,602	(2,863)	336,093
Capital assets	682,322	398,554	191,476 (a)	1,272,352
Energy service arrangements, contracts and relationships	95,716	22,245	61,655 (a)	179,616
Goodwill	18,260	-	108,191 (a)	126,451
Risk management	33,640	-	-	33,640
Long-term investments and other assets	64,509	4,640	(44,746) (b)	24,403
Total assets	1,199,801	459,041	313,713	1,972,555
LIABILITIES AND UNITHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	177,802	33,040	(4,829)	206,013
Distributions payable to unitholders	10,167	2,809	-	12,976
Short-term debt	655	-	-	655
Current portion of long-term debt	1,234	182	-	1,416
Customer deposits	24,369	-	-	24,369
Deferred revenue	1,718	-	-	1,718
Risk management	60,848	-	-	60,848
Other	9,321	-	-	9,321
Total current liabilities	286,114	36,031	(4,829)	317,316
Long-term debt	218,845	91,241	286,281 (c)	596,367
Convertible debentures	-	24,367	(2,196) (d)	22,171
Asset retirement obligations	18,811	4,326	10,024 (a)	33,161
Future income taxes	58,229	71,133	72,895 (e)	202,257
Risk management	30,166	24	-	30,190
Other long-term liabilities	2,948	-	2,542	5,490
	615,113	227,122	364,717	1,206,952
Unitholders' equity	584,688	231,919	(51,004) (f)	765,603
Total liabilities and shareholders' equity	1,199,801	459,041	313,713	1,972,555

See accompanying notes to Pro Forma Consolidated Financial Statements

AltaGas Income Trust

Unaudited Pro Forma Consolidated Income Statement

(Thousands of dollars, except for unit amounts)

Three months ended December 31, 2007

	AltaGas	Taylor	Pro forma Adjustments (note 2)	Pro forma Consolidated
REVENUE				
Operating	335,401	58,522	-	393,923
Unrealized loss on risk management	(502)	(4,683)	-	(5,185)
Fee Income	-	15,078	-	15,078
Other	1,583	266	(775) ^(b)	1,074
	336,482	69,183	(775)	404,890
EXPENSES				
Cost of sales	260,048	41,816	-	301,864
Operating and administrative	36,150	13,100	121 ^(h)	49,371
Amortization	11,394	4,333	611 ^(g)	16,338
	307,592	59,249	732	367,573
Operating income	28,890	9,934	(1,507)	37,317
Interest expense				
Short-term debt	222	-	-	222
Long-term debt	2,683	2,156	3,438 ^(c,d)	8,277
Income before income taxes	25,985	7,778	(4,946)	28,817
Income tax expense (recovery)	(5,818)	(6,700)	(69) ^(b)	(12,587)
Net income (loss)	31,803	14,478	(4,876)	41,405
Net income (loss) per unit (note 3)				
Basic	\$ 0.55			\$ 0.63
Diluted	\$ 0.55			\$ 0.62
Weighted average number of units outstanding (thousands) (note 3)				
Basic	57,960		7,717	65,677
Diluted	57,991		8,893	66,884

See accompanying notes to Pro Forma Consolidated Financial Statements

AltaGas Income Trust

Unaudited Pro Forma Consolidated Income Statement

(Thousands of dollars, except for unit amounts)

Year ended December 31, 2007

	AltaGas	Taylor	Pro forma Adjustments (note 2)	Pro forma Consolidated
REVENUE				
Operating	1,422,242	199,128	-	1,621,370
Unrealized gain (loss) on risk management	1,115	(6,079)	-	(4,964)
Fee Income	-	59,450	-	59,450
Other	5,037	500	(2,815) ^(b)	2,722
	1,428,394	252,999	(2,815)	1,678,578
EXPENSES				
Cost of sales	1,104,399	149,056	-	1,253,455
Operating and administrative	150,297	51,240	483 ^(h)	202,020
Amortization	47,091	17,281	2,445 ^(g)	66,817
	1,301,787	217,577	2,928	1,522,292
Operating income	126,607	35,422	(5,742)	156,287
Interest expense				
Short-term debt	491	-	-	491
Long-term debt	11,394	8,455	13,753 ^(c,d)	33,602
Income before income taxes	114,722	26,967	(19,495)	122,194
Income tax expense (recovery)	5,928	69,100	72,643 ^(b,e)	147,671
Net income (loss)	108,794	(42,133)	(92,139)	(25,478)
Net income (loss) per unit (note 3)				
Basic	\$ 1.90			\$ (0.39)
Diluted	\$ 1.89			\$ (0.39)
Weighted average number of units outstanding (thousands) (note 3)				
Basic	57,382		7,717	65,099
Diluted	57,420		8,893	66,313

See accompanying notes to Pro Forma Consolidated Financial Statements

1. BASIS OF PRESENTATION

On January 10, 2008, AltaGas Income Trust (the Trust or AltaGas) acquired all of the outstanding limited partnership units of Taylor NGL Limited Partnership (Taylor), through its indirect subsidiary, AltaGas Holding Limited Partnership No. 1, (other than the Taylor units already owned by AltaGas and its affiliates) by way of cash consideration of \$256.3 million and 7.7 million AltaGas Trust units valued at \$198.9 million including approximately 0.2 million of Exchangeable units for all of the remaining 91.1 percent of the Taylor units outstanding not previously owned by the Trust.

The Unaudited Pro Forma Consolidated Statements (Pro Forma Statements) have been prepared by management in accordance with Canadian generally accepted accounting principles. Accounting policies used in the preparation of the Pro Forma Statements are consistent with those used in the historical financial statements of the Trust. The Pro Forma Statements should be read in conjunction with the historical financial statements of the Trust for the year ended December 31, 2007. The historical financial statements of the Trust have been filed with the securities commission and are available on www.sedar.com.

The unaudited pro forma consolidated balance sheet gives effect to the assumptions and adjustments described in Note 2 as if the acquisition of Taylor was completed on December 31, 2007, while the unaudited pro forma consolidated statement of income for the three months ended and the year ended December 31, 2007 give effect to the transaction as if the acquisition of Taylor was completed on January 1, 2007.

The Pro Forma Statements may not be indicative of the financial position or results of operations that would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future. In preparing the Pro Forma Statements, no adjustments have been made to reflect any operating or administrative synergies.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

The Pro Forma Statements as at and for the three months ended and the year ended December 31, 2007 reflect the cost of the acquisition using the purchase method. The pro forma purchase equation adjustments and allocation of the purchase price are preliminary and are based on management's estimates of the fair value of the assets acquired and liabilities assumed. Any final adjustments may significantly change the allocation of the purchase price and could affect the fair value assigned to assets and liabilities included in these Pro Forma Statements. The preliminary allocation of the purchase price is as follows:

Total consideration for 100% of Taylor (\$ thousands):

Cost of 8.9% investment in Taylor currently owned by AltaGas		24,672	
Purchase price for the remaining 91.1% of Taylor Units			
Cash consideration	256,281		
Units	198,862		
Estimated transaction costs	11,000		
Equity portion of Taylor			
convertible debentures (note d)	2,127	468,270	
Total consideration			<u>\$ 492,942</u>

Purchase Price Allocation for 100% of Taylor (\$ thousands):

Assets acquired			
Current assets	30,739		
Capital assets	582,000		
Capital projects under development	8,030		
Energy service arrangements, contracts and relationships	83,900		
Goodwill	108,191		
Long-term investments and other assets	4,640	817,500	
Less Liabilities assumed			
Current liabilities	31,202		
Long-term debt	110,241		
Convertible debentures	22,171		
Asset retirement obligation	14,350		
Future income taxes	144,028		
Future employee obligations	2,542		
Risk management	24	324,558	
			<u>\$ 492,942</u>

- a) Pro-forma adjustments have been made to increase the balance of capital assets by \$191.5 million (including \$10.0 million related to the increase in asset retirement obligations). Energy service arrangements, contracts and relationships increased by \$61.7 million to adjust for the estimated fair value of intangible assets acquired. Goodwill has been increased by \$108.2 million to reflect the estimated value of goodwill acquired, including goodwill arising as a result of the future income tax liability of \$72.9 million.
- b) Prior to acquisition completed on January 10, 2008 the Trust owned 8.9 percent of Taylor which it had been accounting for using the fair value method as an available for sale financial instrument. Prior to the acquisition of the remaining 91.1 percent of the Taylor units, AltaGas had reported a mark-to-market gain of \$20.1 million on its investment in Taylor in the Other Comprehensive Income component of equity. For purposes of the Pro Forma Statements, the previously reported mark-to-market gain was reversed and the investment in Taylor was reduced by \$20.1 million to its historic cost amount. The remaining book value of the investment in Taylor of \$24.7 million was allocated as part of the purchase price equation for a total reduction of \$44.7 million in the investment in Taylor. Revenue decreased by \$0.8 million and \$2.8 million and income tax expense decreased by \$0.1 million and \$0.3 million for the three months ended and the year ended December 31, 2007 respectively to eliminate the income from the Taylor investment previously reported.
- c) AltaGas financed the cash consideration of \$256.3 million for the acquisition through its revolving credit facility. Assuming this debt remained consistent throughout the pro forma periods at AltaGas' weighted average rate of variable debt in each period, AltaGas would have incurred approximately \$3.5 million and \$14.2 million of interest charges for the three months ended and the year ended December 31, 2007 respectively.
- d) The Trust assumed the obligation of \$22.1 million principal amount of Taylor Convertible Debentures. The fair value of the debentures as at December 31, 2007 has been estimated by AltaGas, as a result of the substitution of AltaGas units as the conversion instrument, and allocated between a liability and equity component in the amounts of \$22.2 million and \$2.1 million respectively. As a result, the liability component of the convertible debentures previously reported by Taylor has been decreased by \$2.2 million and increased the equity component by \$0.9 million. The effect of the difference in the allocation of the liability and equity components resulted in a decrease in the interest expense by \$0.1 million and \$0.4 million for the three months ended and the year ended December 31, 2007 respectively.
- e) For purposes of the Pro Forma Statements as at December 31, 2007, the tax on Specified Investment Flow Through (SIFT) entities was adjusted to account for the change in temporary differences resulting from the acquisition. Future income taxes as at December 31, 2007 and the related tax expense for the year ended December 31, 2007 increased by \$72.9 million as a result of the increase in the fair value of the depreciable assets recorded as part of the purchase price equation. There was no effect on the three months ended December 31, 2007.
- f) Unitholder equity has been adjusted as follows:

(\$ thousands)	
Eliminate Taylor equity	\$ (230,724)
Eliminate Taylor equity portion of convertible debentures	(1,195)
AltaGas units issued upon acquisition (note 2)	198,862
Equity portion of convertible debentures (note 2d)	2,127
Elimination of mark-to-market adjustment on AltaGas investment in Taylor prior to the acquisition (note 2b)	(20,074)
	<u>\$ (51,004)</u>

- g) Amortization expense increased by \$0.6 million and \$2.4 million for the three months ended and the year ended December 31, 2007 respectively due to the increase to fair value of assets subject to amortization resulting from the acquisition and consistent with AltaGas' current amortization policy.
- h) As a result of the increase in the asset retirement obligation of \$10.0 million, the accretion expense increased by \$0.1 million and \$0.5 million for the three months ended and the year ended December 31, 2007.

3. EARNINGS PER UNIT

Basic and diluted net income per unit for the year ended December 31, 2007 have been calculated assuming the increase of 7.6 million Trust Units as of January 1, 2007 issued upon completion of the acquisition as well as the dilutive effect of 0.9 million Trust units issuable upon conversion of the Taylor Convertible Debentures. The pro forma weighted average number of Trust Units outstanding for the three months ended and year ended December 31, 2007 is as follows:

	Three months ended December 31, 2007	Year ended December 31, 2007
Basic	65,677	65,099
Diluted	66,884	66,313

Taylor NGL Limited Partnership

**Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and Deficit
and
Statement of Cash Flows**

For the Three Months Ending December 31, 2007 and 2006

TAYLOR NGL LIMITED PARTNERSHIP

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and Deficit
(Stated in thousands of dollars except per unit amounts)

	Three Months ended December 31	
	2007	2006
	(unaudited)	(unaudited)
Revenue:		
Natural gas liquids sales	\$ 58,522	\$ 49,723
Fee income	15,078	15,743
Other	264	23
	<u>73,864</u>	<u>65,489</u>
Expenses:		
Feedstock costs	41,816	38,797
Operating costs	10,093	12,129
Depreciation, amortization and accretion	4,333	4,376
Administration	3,007	1,976
Interest	2,156	2,126
Financial instruments losses (gains)	4,667	(1,661)
Foreign exchange loss	16	-
Investment income	(2)	-
	<u>66,086</u>	<u>57,743</u>
Net income before future income taxes	7,778	7,746
Future income taxes	(6,700)	-
Net income (loss) and comprehensive income (loss)	14,478	7,746
Deficit, beginning of period	(115,294)	(34,503)
Unitholders' distributions declared	(8,197)	(7,979)
Deficit, end of period	\$ (109,013)	\$ (34,736)
Net income (loss) per Partnership unit:		
Basic	\$ 0.34	\$ 0.18
Diluted	\$ 0.32	\$ 0.18

TAYLOR NGL LIMITED PARTNERSHIP

Consolidated Statements of Cash Flow
(Stated in thousands of dollars)

	Three Months ended December 31	
	2007	2006
	(unaudited)	(unaudited)
Cash provided by (used in):		
Operations:		
Net income (loss)	\$ 14,478	\$ 7,746
Future income taxes	(6,700)	-
Depreciation, amortization and accretion	4,333	4,376
Unrealized losses (gains) on financial instruments	3,673	(1,012)
Accretion of convertible debentures discount	105	105
Partnership unit-based compensation	27	44
Non-cash employee future benefits expense	31	119
Unrealized foreign exchange loss (gain)	(94)	10
Investment income	(2)	-
	<u>15,851</u>	<u>11,388</u>
Change in non-cash working capital	(1,718)	1,883
	<u>14,133</u>	<u>13,271</u>
Financing:		
Unitholders' distributions paid	(8,050)	(7,979)
Long-term debt	(1,000)	(2,000)
Boston Bar Loan repayments	(43)	-
Units issued for cash, net of issue costs	-	14
	<u>(9,093)</u>	<u>(9,965)</u>
Investments:		
Capital expenditures	(5,874)	(1,772)
Investment distributions	134	-
Change in non-cash investing working capital	1,432	318
	<u>(4,308)</u>	<u>(1,454)</u>
Effect of exchange rate changes on cash	94	(10)
Change in cash and cash equivalents	826	1,842
Cash and cash equivalents, beginning of period	1,398	868
Cash and cash equivalents, end of period	\$ 2,224	\$ 2,710

Taylor NGL Limited Partnership
Audited Consolidated Financial Statements
For the Year Ended December 31, 2007 and 2006



KPMG LLP
Chartered Accountants
2700 205 - 5 Avenue SW
Calgary AB T2P 4B9

Telephone (403) 691-8000
Telefax (403) 691-8008
Internet www.kpmg.ca

AUDITORS' REPORT TO THE BOARD OF DIRECTORS OF TAYLOR GAS LIQUIDS LTD. AS GENERAL PARTNER OF TAYLOR NGL LIMITED PARTNERSHIP

We have audited the consolidated balance sheets of Taylor NGL Limited Partnership as at December 31, 2007 and 2006 and the consolidated statements of income (loss) and comprehensive income (loss) and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Partnership 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.

KPMG LLP

Chartered Accountants

Calgary, Canada
February 5, 2008

KPMG LLP, a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

TAYLOR NGL LIMITED PARTNERSHIPConsolidated Balance Sheets
(Stated in thousands of dollars)

As at December 31,	2007	2006
Assets		
Current assets:		
Cash and cash equivalents	\$ 2,224	\$ 2,710
Accounts receivable	30,153	25,708
Prepaid expenses and interest	1,225	1,456
	<u>33,602</u>	<u>29,874</u>
Fair value of financial instruments (note 17)	-	663
Investment (note 5)	4,640	-
Capital assets (notes 3 and 4)	398,554	391,365
Intangible assets (notes 3 and 4)	22,245	19,141
Deferred financing costs (note 2)	-	1,415
	<u>\$ 459,041</u>	<u>\$ 442,458</u>
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 33,040	\$ 19,874
Unitholders' distributions payable	2,809	2,660
Current portion of long-term debt (note 6)	182	-
	<u>36,031</u>	<u>22,534</u>
Fair value of financial instruments (note 17)	24	207
Long-term debt (note 6)	91,241	85,000
Convertible debentures (notes 2 and 7)	24,367	48,387
Asset retirement obligations (note 8)	4,326	3,969
Future income taxes (note 9)	71,133	-
	<u>227,122</u>	<u>160,097</u>
Unitholders' equity (note 10):		
Unitholders' capital	339,288	314,483
Convertible debentures	1,195	2,325
Contributed surplus	449	289
Deficit	(109,013)	(34,736)
	<u>231,919</u>	<u>282,361</u>
Subsequent event (note 1)		
Commitments (note 16)		
Guarantees (note 18)		
Insurance claims and contingencies (note 19)		
	<u>\$ 459,041</u>	<u>\$ 442,458</u>

See accompanying notes to consolidated financial statements.

TAYLOR NGL LIMITED PARTNERSHIP

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss) and Deficit
(Stated in thousands of dollars except per unit amounts)

Years ended December 31,	2007	2006
Revenue:		
Natural gas liquids sales	\$ 199,128	\$ 197,802
Fee income	59,450	57,875
Other	370	146
	<u>258,948</u>	<u>255,823</u>
Expenses:		
Feedstock costs	149,056	153,886
Operating costs	41,740	41,840
Depreciation, amortization and accretion	17,281	17,588
Administration	9,500	6,263
Interest	8,455	8,325
Financial instruments losses (gains) (note 17)	5,898	(835)
Foreign exchange loss	181	30
Investment income (note 5)	(130)	-
	<u>231,981</u>	<u>227,097</u>
Net income before future income taxes	26,967	28,726
Future income taxes (notes 2 and 9)	69,100	-
Net income (loss) and comprehensive income (loss)	(42,133)	28,726
Deficit, beginning of year	(34,736)	(32,188)
Unitholders' distributions declared	(32,144)	(31,274)
Deficit, end of year	<u>\$ (109,013)</u>	<u>\$ (34,736)</u>
Net income (loss) per Partnership unit (note 13):		
Basic	\$ (0.99)	\$ 0.68
Diluted	\$ (0.99)	\$ 0.68

See accompanying notes to consolidated financial statements.

TAYLOR NGL LIMITED PARTNERSHIP

Consolidated Statements of Cash Flow
(Stated in thousands of dollars)

Years ended December 31,	2007	2006
Cash provided by (used in):		
Operations:		
Net income (loss)	\$ (42,133)	\$ 28,726
Future income taxes (notes 2 and 9)	69,100	-
Depreciation, amortization and accretion	17,281	17,588
Unrealized losses (gains) on financial instruments (note 17)	4,638	(215)
Accretion of convertible debentures discount	417	417
Partnership unit-based compensation	160	164
Non-cash employee future benefits expense (note 14)	130	119
Investment income (note 5)	(130)	-
Unrealized foreign exchange loss	8	40
	<u>49,471</u>	<u>46,839</u>
Change in non-cash working capital (note 15)	(2,262)	(3,577)
	<u>47,209</u>	<u>43,262</u>
Financing:		
Unitholders' distributions paid	(31,995)	(31,166)
Long-term debt	5,000	(6,000)
Units issued for cash, net of issue costs	264	132
Boston Bar Loan repayments (note 6)	(84)	-
	<u>(26,815)</u>	<u>(37,034)</u>
Investments:		
Capital expenditures	(18,104)	(8,291)
Acquisition (note 4)	(9,436)	-
Investment distributions (note 5)	267	-
Change in non-cash investing working capital (note 15)	6,401	407
	<u>(20,872)</u>	<u>(7,884)</u>
Effect of exchange rate changes on cash	(8)	(40)
Change in cash and cash equivalents	(486)	(1,696)
Cash and cash equivalents, beginning of year	2,710	4,406
Cash and cash equivalents, end of year	<u>\$ 2,224</u>	<u>\$ 2,710</u>

See accompanying notes to consolidated financial statements.

TAYLOR NGL LIMITED PARTNERSHIP

Notes to the Consolidated Financial Statements

Years ended December 31, 2007 and 2006

(all tabular amounts are stated in thousands of dollars except unit amounts)

1. Organization

In January 2008, AltaGas Income Trust ("AltaGas") acquired all of the outstanding Units of the Taylor NGL Limited Partnership (the "Partnership"). In conjunction with the acquisition, the Partnership incurred certain costs as specified under the Support Agreement between AltaGas and the Partnership dated November 11, 2007. These obligations included transaction costs of approximately \$4.4 million and employee obligations of approximately \$2.3 million. In addition, the Partnership was required to settle with the holders of outstanding options, which were previously granted under the Partnership's Unit Option Plan, equal to the difference between the offer price of \$11.20 per Unit and the associated exercise price of the option. Furthermore, pursuant to the terms of the Support Agreement between the Partnership and AltaGas, all outstanding RSUs, including those that were granted on January 1, 2008, were to be redeemed prior to the change in control based on the \$11.20 per Unit offer price. Taylor used its revolving credit facility to fund these payments. The terms of Taylor's credit facility was amended as a result of the acquisition. The credit facility matures on June 28, 2008, at which time all amounts drawn under the facility are repayable. In addition, as a result of the acquisition, the outstanding convertible debentures are convertible into trust units of AltaGas at a conversion price of \$24.64 per trust unit.

The Partnership was formed July 31, 2000 under the laws of the Province of Ontario pursuant to a limited partnership agreement. The general partner of the Partnership was Taylor Gas Liquids Ltd. ("TGLL" or "General Partner"), while the limited partners were the public, holding Partnership units ("Units").

The Partnership and its wholly owned subsidiaries and partnerships were comprised as follows:

Entity	Year Acquired or Built by Taylor	Asset / Relationship
Taylor Gas Liquids Limited Partnership ("TGLLP")	1996	Younger Extraction Plant
Joffre Gas Liquids Limited Partnership ("JGLLP")	2001 2004 2004	Joffre Extraction Plant Ethylene Delivery System ("EDS") Joffre Feedstock Pipeline ("JFP")
Taylor Gas Processing Limited Partnership ("TGPLP")	2003 2003 2003 2003	Retlaw Gas Processing Plant Enchant Gas Processing Plant Turin Gas Processing Plant Related natural gas gathering systems (collectively the "RET Complex")
Harmattan Gas Processing Limited Partnership ("HGPLP")	2005	Harmattan Gas Processing Complex ("Harmattan Complex")
Taylor Management Inc. ("TMI")	2005	general partner of TGLLP, JGLLP and TGPLP
Taylor Processing Inc. ("TPI")	2005	general partner of HGPLP ("Harmattan Complex")
Highwater Power Limited Partnership ("HWPLP")	2007	Log Creek and Kookipi Creek Hydroelectric Development Projects
Highwater Power Corporation ("Highwater")	2007	general partner of HWPLP and limited partner of Boston Bar LP

Collectively, TGLLP, JGLLP, TGPLP, HGPLP and HWPLP were known as the "Operating Partnerships". The Partnership made cash distributions to its unitholders, subject to the Partnership's limited partnership agreement, to the extent that the Partnership had cash available for such payment less unpaid expenses, amounts required for the business and operation of the Partnership and any cash reserve which the board of directors of the General Partner in its discretion determined necessary to satisfy the Partnership's current and anticipated obligations and liabilities.

2. Significant Accounting Policies

Basis of presentation

These consolidated financial statements include the accounts of the Partnership and all of its wholly owned subsidiaries and partnerships.

Certain comparative figures have been reclassified to conform to the current year's presentation.

Joint ventures

The Operating Partnerships contain businesses that are conducted jointly with others, and accordingly these financial statements reflect only the Partnership's indirect proportionate interest in such activities.

Estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts. These estimates are subject to uncertainty and may affect the financial statements of future periods. The recognized amounts of such items are based on management's best information and judgment.

Revenue

All natural gas liquids ("NGL") produced by TGLLP at the Younger Extraction Plant are sold at the outlet of the plant under a long-term marketing agreement (the "NGL Purchase Agreement") with Provident Energy Trust ("Provident"). Pursuant to the terms of the NGL Purchase Agreement, TGLLP's revenue is the sum of a return-on-capital fee, recovery of operating costs and natural gas costs and a 50 percent share of the proceeds received from the final sale of NGL by Provident net of all costs (the "Marketing Pool"). If Provident's revenue from the sale of the NGL acquired from the TGLLP does not exceed costs, then future net proceeds will only accrue to TGLLP after any deficiency is retired. During 2007, the Marketing Pool contributed \$16.3 million in revenue, net to TGLLP (2006 – \$10.2 million).

If the Marketing Pool deficiency is greater than \$1.75 million gross at two consecutive calendar year ends, Provident has the right to terminate the NGL Purchase Agreement by giving notice to the Partnership during the first 60 days of the following calendar year and remit a significant termination payment. Provident does not currently have the right to terminate the NGL Purchase Agreement.

The ethane produced at the Joffre Extraction Plant is sold at the outlet of the plant under a long-term sales agreement (the "Ethane Supply Agreement"). Pursuant to the terms of the Ethane Supply Agreement, the sales price is the sum of a return-on-capital charge and recovery of the operating costs attributed to the production of ethane. The remaining NGL (propane, butane and condensate, collectively known as "Propane-Plus") produced at the Joffre Extraction Plant are sold into the Alberta market at prevailing prices. The Partnership's share of revenue received under the Ethane Supply Agreement and the sale of Propane-Plus is included in NGL sales.

Revenue for processing services at the RET Complex and Harmattan Complex is recorded as the services are rendered. Processing fees that are a function of volumes processed are recognized in the period in which the processing occurs. Fees that are not directly related to volumes processed, such as capital recovery, are recognized at stipulated rates over the contract periods. Fees derived from the recovery of operating expenses are recognized in the period in which the expenses are incurred.

Revenue from the Harmattan Complex also includes the sale of ethane, frac oil, industrial grade liquid carbon dioxide ("CO₂") and Propane-Plus production. Under the terms of many of the raw natural gas processing agreements, a component of the compensation received by the Partnership for providing services to the producers is derived from the Partnership having the right to purchase a portion of the producers' ethane and Propane-Plus for a price based on the natural gas heat equivalent. The ethane acquired by the Partnership under the product-in-kind arrangements is sold under a long-term contract for a price that includes full recovery of the cost of acquiring the ethane from the producers plus a premium. Frac oil is a premium hydrocarbon-based product that is produced by refining condensate feedstock. Harmattan's frac oil is sold to

a single customer. CO₂ is recovered through the processing of raw natural gas to meet sales gas specifications. The liquid CO₂ is sold to a single customer under a take-or-pay contract with approximately 6 years remaining. The Propane-Plus volumes acquired by the Partnership are sold into the Alberta market at prevailing prices.

The terms for use of EDS and JFP are defined by long-term transportation agreements. Revenue received for use of the pipelines is the sum of a fixed transport-or-pay fee and the full recovery of actual costs incurred in operating the pipelines, and is recorded as fee income.

Inventory

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

Capital assets

The Younger Extraction Plant and the Joffre Extraction Plant are depreciated over a 40-year period, commencing July 1996 and January 2003, respectively, using the straight-line method of depreciation.

The RET Complex is depreciated over a 25-year period, commencing September 1, 2003, using the straight-line method. Included in the RET Complex capital assets is \$1.0 million of intangible assets assigned to the natural gas processing contracts that were in place at the date of purchase of this facility. Amortization of the intangible assets was provided for on a straight-line basis over three years representing the period wherein the majority of the expected revenues from these contracts will be realized by the Partnership. At December 31, 2006, these intangible assets had been fully amortized.

The EDS pipeline is depreciated over a 25-year period, commencing September 1, 2004, using the straight-line method. The JFP pipeline is depreciated over a 40-year period, commencing March 15, 2005, using the straight-line method.

The Harmattan Complex is being depreciated over a 30-year period using the straight-line method of depreciation commencing March 22, 2005. Amortization of the intangible assets that were acquired along with the Harmattan Complex is provided for on a straight-line basis over nine years.

Taylor is currently developing two ten megawatt run-of-river hydroelectric projects in British Columbia as part of Taylor's acquisition of Highwater in June 2007. Development costs, along with \$5.7 million of intangible assets allocated to the electricity purchase agreements with B.C. Hydro, will be amortized over 40 years upon commencement of operations for each of the run-of-river hydroelectric projects.

Capital assets are recorded at cost less depreciation, net of any impairment in the carrying amount. Acquisition costs are capitalized and amortized over the life of the acquired assets. Repairs and maintenance costs are expensed in the period incurred.

Asset retirement obligations

The fair value of estimated asset retirement obligations ("ARO") is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized ARO amount for a particular asset is depreciated on a straight-line basis over the life of such asset. The long-term liability amount typically increases each reporting period due to accretion. Revisions to the estimated timing of cash flows or to the estimated undiscounted cost would also result in an increase or decrease to the ARO. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Partnership's net income in the period in which such settlement occurs.

Income taxes

On June 12, 2007, the Government of Canada substantively enacted legislation to tax the income of flow-through entities, including publicly-traded limited partnerships, beginning in 2011. As a result, a portion of the Partnership's future income that would have otherwise been distributed to Unitholders is subject to income tax beginning in the fiscal year 2011. As a result of this new legislation, the Partnership is required to record future income taxes in the consolidated financial statements in accordance with Canadian accounting standards. The Partnership follows the asset and liability method for recording future income taxes whereby future tax assets and liabilities are recognized on differences between the carrying value of assets and liabilities and their respective tax bases using tax rates that are expected to apply when these differences reverse. Future tax assets are recognized in circumstances where it is considered more likely than not that the related income tax deductions will be realized.

Furthermore, future income tax liabilities and assets are recognized on acquisitions and reflect the difference between the assigned fair values for assets and liabilities and their respective tax bases using tax rates that are expected to apply when these differences reverse. Future tax liabilities are allocated to tangible and intangible assets based on the estimated fair value allocated to these assets in the purchase price equation. Consideration paid on acquisitions in excess of the estimated fair value of the net assets acquired, including future tax liabilities, is allocated to goodwill.

Compensation plans

The Partnership uses the fair value method to account for options granted to employees and directors. Under the fair value method, the fair value of the options is estimated at the grant date using the Black-Scholes option pricing methodology, and such fair value is expensed over the vesting period, with a corresponding increase in contributed surplus.

The Partnership has implemented a Long-Term Incentive Plan ("LTIP"), details of which are described in note 12. The LTIP compensates officers, directors and certain employees by awarding Restricted Share Units ("RSUs"). On the date the RSU vests, the holder receives a cash payment equal to the volume-weighted market price of Partnership units for ten trading days preceding the vesting date. The market price of Partnership units multiplied by the number of issued RSUs is recognized as compensation expense over the vesting period. Compensation cost is increased or decreased each reporting period as the Partnership unit market price fluctuates. From the effective date of the RSU award, the holder of RSUs receives additional RSUs equal to the cash distributions that would be paid on the number of Partnership units that the RSUs held represent. The distribution-equivalent RSUs are recognized as compensation expense over the same vesting period.

Employee pension plan

The Partnership has a defined benefit pension plan for the unionized Younger Extraction Plant employees that covered 24 active members, 3 retired and 2 deferred members as at December 31, 2007. In addition, the Partnership has a defined benefit pension plan for certain employees of the Harmattan Complex, which is not open to new members. As at December 31, 2007, this plan covered 11 active members and 3 retired members. The cost of pension benefits earned by such employees in the defined benefit plan is charged to income as services are rendered using the projected benefit method prorated for service. The cost of the defined benefit plan is based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality and other factors affecting the payment of future benefits. If adjustments in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets at the beginning of the year were required due to plan amendments, changes in assumptions or experience, the resulting gains and losses would be amortized over the expected remaining average service life of the employee group. If the defined benefit pension plan is terminated and not replaced by a successor defined benefit plan, the Partnership will account for a curtailment first and then a settlement, whenever a curtailment and a settlement occur at the same time.

In addition to pension benefits, the Partnership provides post-retirement benefits for its unionized employees at the Younger Extraction Plant and employees at the Harmattan Complex.

Foreign currency

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

Cash and cash equivalents

Cash and cash equivalents include short-term investments with terms to maturity of three months or less at the time of purchase.

Financial instruments and comprehensive income

On January 1, 2007, the Partnership adopted the new CICA Handbook Section 3855 "Financial Instruments -- Recognition and Measurement", Section 3861 "Financial Instruments -- Disclosure and Presentation", Section 1530 "Comprehensive Income", Section 3251 "Equity" and Section 3865 "Hedges" on a prospective basis.

Section 3855 establishes standards for the recognition and measurement of all financial instruments, provides a characteristics-based definition of a derivative financial instrument, provides criteria for determining when a financial instrument should be recognized, and provides criteria for determining when a financial instrument is to be extinguished. The Partnership has elected to use January 1, 2003 as the transition date for applying Section 3855 to embedded derivatives.

The Partnership uses derivative financial instruments such as collars and swaps to manage exposure to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as described in note 17. The Partnership does not utilize derivative financial instruments for trading or speculative purposes. Management was required to obtain approval from the Audit Committee of the General Partner prior to entering into derivative financial instruments. The derivative financial instruments are designated as held for trading under the new accounting standards, whereby a derivative financial instrument is recorded as an asset or a liability on the balance sheet, and changes in the fair value relating to a financial period can either reduce or increase net income and net income per Partnership unit for that period. The change in the fair value of derivative financial instruments is recorded in the income statement as gains or losses on financial instruments, including cash payments or receipts when the derivative financial instruments are settled.

Section 1530 and Section 3251 establish standards for reporting comprehensive income. These standards require that an enterprise present comprehensive income, and its components, in a separate financial statement that is displayed with the same prominence as other financial statements.

Section 3865 provides guidance for entities that choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13, "Hedging Relationships", and on the hedging guidance in Section 1650, "Foreign Currency Translation", by specifying how hedge accounting is applied and what disclosure it requires.

There was no significant impact to the financial statements as a result of implementing these new standards, except as noted below.

Under these new accounting standards, the Partnership has elected to record financing costs incurred as a reduction to the related financing. In 2006, financing costs were reflected as deferred charges. The financing costs will be charged to earnings over the anticipated life of the related financing using the effective interest rate method. On January 1, 2007, the Partnership reclassified the deferred financing costs of \$1.4 million, which related to the convertible debenture offering, against the debt portion of the convertible debentures. The difference between the amount charged to earnings as amortization of the deferred costs and the amount that would have been charged to earnings, had the effective interest rate method been used, was not significant.

Per Partnership unit information

Basic net income per Partnership unit is calculated based on the weighted-average number of Partnership units outstanding during the year. Diluted net income per Partnership unit is calculated based on the number of Partnership units that would have been obtained upon exercise of options to purchase Partnership units at the quarterly average market close price plus the number of Partnership units issuable on conversion of outstanding convertible debentures. In addition, in calculating diluted net income per Partnership unit, net income is increased by the interest on the convertible debentures and accretion of the convertible debenture discount.

Convertible debentures

Convertible debentures are recorded at the amount of proceeds received less the amount attributed to the conversion feature, which is included as part of unitholders' equity. The difference between the recorded amount and the face value of the convertible debentures is charged to income on an effective yield basis.

Future accounting changes

On January 1, 2008, the Partnership is required to adopt CICA 1535, "Capital Disclosures". This standard requires the disclosure of information related to the objectives, policies and processes for managing capital. This standard has no impact on the Partnership's financial results as it only addresses disclosure requirements.

On January 1, 2008, the Partnership is required to adopt CICA 3862, "Financial Instruments – Disclosures". CICA 3862 requires disclosure of information related to the significance of financial instruments to the Partnership's performance. The Partnership is also required to disclose information related to the risks of its use of financial instruments and how those risks are managed. As this standard only addresses presentation and disclosure requirements, there will be no impact to the Partnership's financial results.

3. Capital Assets and Intangible Assets

	2007	2006
Property, plant and equipment	\$ 365,946	\$ 354,430
Accumulated depreciation	(56,744)	(45,411)
Pipelines	87,594	87,424
Accumulated depreciation	(7,635)	(5,078)
Capital assets under development	9,393	–
	398,554	391,365
Intangible assets	30,505	24,761
Accumulated amortization	(8,260)	(5,620)
	22,245	19,141
	\$ 420,799	\$ 410,506

Interest and financing fees of \$0.2 million were capitalized during 2007 (2006 – nil). The Partnership has capitalized \$1.8 million of third-party costs and \$0.4 million of general and administrative costs related to the Harmattan Co-stream Project, which is currently not subject to depreciation. The project is anticipated to bring natural gas from TransCanada's Alberta system to the Harmattan Complex for processing to recover ethane, propane, butane and condensate.

4. Acquisition

On June 22, 2007, the Partnership acquired approximately 90 percent of the issued and outstanding common shares of Highwater Power Corporation ("Highwater"). The remaining common shares were acquired on September 13, 2007 for approximately \$870,000. Highwater has a 25 percent interest in class A and B partnership units of Boston Bar Limited Partnership, which operates a seven megawatt run-of-river hydroelectric facility located on Scuzzy Creek, British Columbia. In addition, Highwater is developing two ten megawatt run-of-river hydroelectric projects in British Columbia.

The cash consideration paid to acquire all of the common shares of Highwater tendered to the Partnership's offer was \$9.4 million, including transaction costs of approximately \$0.4 million. The Highwater acquisition is summarized as follows:

Intangible assets	\$ 5,744
Investment in Boston Bar Limited Partnership (note 5)	4,777
Capital assets in development	2,974
Current assets	759
Current liabilities	(1,284)
Boston Bar Loan (note 6)	(1,501)
Future income tax liabilities (note 9)	(2,033)
	\$ 9,436

On March 22, 2005, the Partnership acquired the Harmattan Complex, through the purchase of all the outstanding shares of two private companies. At December 31, 2007, the Partnership has withheld \$2.3 million from the former owners of the Harmattan Complex as a reserve against future obligations should they arise prior to December 2008.

5. Investment

The Partnership records its interest in Boston Bar Limited Partnership using the equity method of accounting whereby the Partnership includes in earnings, its proportionate share of the earnings of Boston Bar Limited Partnership. Distributions received from Boston Bar Limited Partnership are recorded as a reduction in the equity investment.

Balance, December 31, 2006	\$	—
Acquisition of investment in Boston Bar Limited Partnership (note 4)		4,777
Current period share of Boston Bar Limited Partnership earnings		130
Distributions from Boston Bar Limited Partnership		(267)
Balance, December 31, 2007	\$	4,640

6. Long-term Debt

	December 31 2007	December 31 2006
Revolving credit facility	\$ 90,000	\$ 85,000
Boston Bar Loan	1,423	—
Current portion of the Boston Bar Loan	(182)	—
	\$ 91,241	\$ 85,000

At December 31, 2007, the Partnership's \$120 million revolving credit facility was drawn by \$90 million (December 31, 2006 – \$85 million). During the second quarter of 2007, the Partnership's \$120 million revolving credit facility was extended for a further 364-day period commencing June 30, 2007. At expiry, June 29, 2008, the facility can be extended at the lenders' option for another 364 days. If the revolving credit facility is not extended, the amount drawn is fully repayable on June 29, 2009. The revolving credit facility bears interest at bankers' acceptance rates, plus stamping fees, plus applicable margins. The margins and stamping fees vary depending on financial statement ratios and can range from 1.15 percent to 1.65 percent. The revolving credit facility agreement provides several financial covenants that the Partnership must fulfill, unless written exception is provided by the lenders:

	Covenant Requirement	Ratio at December 31, 2007
Debt to earnings before interest, tax and depreciation ratio	less than 3.5:1	1.75:1
Interest coverage ratio	greater than 3.0:1	9.88:1
Debt to capitalization ratio	less than 0.6:1	0.27:1

During 2007 and 2006, the Partnership complied with the covenants contained in the revolving credit facility agreement.

The Partnership also has a \$10 million operating facility. As at December 31, 2007, the amount available under this facility was reduced by \$2.9 million to support outstanding letters of credit.

The revolving credit facility and the operating facility are secured by a first ranking floating charge debenture on all of the Partnership's assets.

Upon acquisition of Highwater (note 4), the Partnership assumed the outstanding debt within Highwater that was associated with its partnership interest in Boston Bar Limited Partnership, which had an estimated fair value of \$1.5 million (the "Boston Bar Loan"). At December 31, 2007, the Boston Bar Loan had principal outstanding of \$1.9 million, which bears interest at 10.75 percent per annum, compounded monthly, repayable in blended monthly payments of \$31,974 over a twenty-year term that expires May 2015. For the year ended December 31, 2007, the Partnership made principal payments of \$84,000 on the Boston Bar Loan.

The Boston Bar Loan is secured by a mortgage over Boston Bar Limited Partnership's power generation assets and Highwater's interest in Boston Bar Limited Partnership. Principal repayments on the Boston Bar Loan are scheduled to average \$275,000 per year for the next five years.

The average annual effective interest rate on the Partnership's debt for 2007, including the Partnership's convertible debentures, was 6.1 percent (2006 – 5.7 percent).

7. Convertible Debentures

On March 22, 2005, the Partnership issued \$50 million of 5.85 percent convertible debentures maturing on September 10, 2010, with interest payable semi-annually in arrears on September 10 and March 10 in each year. The proceeds of the issue, net of underwriters' fees and costs, were \$47.9 million. Prior to maturity, the debentures may be converted into Partnership units at the option of the holder, at a conversion price of \$10.35 per Partnership unit. Underwriters' fees and costs of \$2.1 million are being amortized over the life of the convertible debentures using the effective interest method.

The Partnership may redeem the convertible debentures after September 10, 2008 and prior to September 10, 2009, in whole or in part, at a price equal to their principal amount plus accrued and unpaid interest, if any, provided the current market price of the Partnership units on the date notice is given is not less than 125 percent of the conversion price, subject to adjustment in certain events. After September 10, 2009 and prior to the convertible debentures' maturity, the Partnership may redeem the convertible debentures at a price equal to their principal amount plus accrued and unpaid interest, if any. The Partnership can elect to pay interest on the debentures by issuing Partnership units.

Balance, December 31, 2005	\$ 47,970
Accretion of discount	417
Balance, December 31, 2006	\$ 48,387
Accretion of discount	417
Financing costs	(1,026)
Conversions	(23,411)
Balance, December 31, 2007	\$ 24,367

During the year, convertible debentures with an aggregate principal value of \$24.3 million were converted at \$10.35 per Partnership unit resulting in 2,345,111 Partnership units being issued (note 10).

At December 31, 2007, the convertible debentures had an estimated fair value of \$26.3 million (2006 – \$49.2 million) and outstanding principal value of \$25.7 million.

8. Asset Retirement Obligations

The Partnership has estimated the net present value of its asset retirement obligations to be \$4.3 million as at December 31, 2007 (2006 – \$4.0 million), based on an undiscounted future liability of \$100.8 million, excluding salvage values, unchanged from December 31, 2006. The earliest of these payments is not expected before 2029, with the majority not expected to begin until 2043. The Partnership's credit adjusted risk-free rate of 9 percent and an inflation rate of 1.5 percent were used to calculate the present value of the asset retirement obligation. The following table reconciles the Partnership's total asset retirement obligation:

	2007	2006
Asset retirement obligations, beginning of year	\$ 3,969	\$ 3,641
Accretion expense	357	328
Asset retirement obligations, end of year	\$ 4,326	\$ 3,969

9. Future Income Taxes

A continuity of the future income tax liability is as follows:

Balance, December 31, 2006	\$	–
Impact of change to income tax legislation		75,000
Future income tax liability on acquisition (note 3)		2,033
Impact of change to income tax rate		(8,000)
Other period future income tax expense		2,100
Balance, December 31, 2007	\$	71,133

The components of the future income tax liability at December 31, 2007 are as follows:

Future income tax liabilities:	
Capital assets and intangible assets	\$ 75,446
Future income tax assets:	
Non-capital losses (expire 2011 to 2024)	(1,813)
Asset retirement obligation	(1,200)
Partnership unit issue costs	(1,300)
	(4,313)
Net future income tax liability	\$ 71,133

The Partnership recorded a future income tax expense of \$75.0 million in the second quarter of 2007 as a result of the new tax legislation, which used an effective income tax rate of 29.4 percent. This future tax expense was based on temporary differences that are expected to reverse after December 31, 2010, the effective date of the tax on flow-through entities.

On October 30, 2007, the Government of Canada announced changes to the general corporate tax rate to occur between 2008 and 2012. As a result, the effective income tax rate for the Partnership was reduced to 26.7 percent, which decreased the future income tax liability by \$8.0 million.

10. Unitholders' Equity

	2007	2006
Unitholders' capital	\$ 339,288	\$ 314,483
Accumulated earnings	42,418	84,551
Convertible debentures	1,195	2,325
Contributed surplus	449	289
Accumulated distributions	(151,431)	(119,287)
	\$ 231,919	\$ 282,361
	Number of Units	Amount
Balance, December 31, 2005	42,535,240	\$ 284,613
Net income for the year ended December 31, 2006		28,726
Unitholders' distributions declared		(31,274)
Units issued on exercise of options	20,000	139
Contributed surplus		157
Balance, December 31, 2006	42,555,240	\$ 282,361
Net loss for the year ended December 31, 2007		(42,133)
Unitholders' distributions declared		(32,144)
Units issued on conversion of convertible debentures	2,345,111	23,411
Increase in unitholders' capital from equity portion of convertible debentures		1,130
Decrease in equity component of convertible debentures on conversions		(1,130)
Units issued on exercise of options	35,750	264
Contributed surplus		160
Balance, December 31, 2007	44,936,101	\$ 231,919

The Partnership is authorized to issue an unlimited number of voting Partnership units.

11. Partnership Unit Option Plan

The Partnership may provide additional compensation to the General Partner's employees, officers and directors by granting options under the Partnership Unit Option Plan (the "Unit Option Plan"). The Unit Option Plan provides for the issuance of options to acquire Partnership units. As at December 31, 2007, the Unit Option Plan was limited to granting 3,283,650 Partnership units, of which 2,105,152 Partnership units remain available. Options granted under the plan generally vest over three years. The outstanding options expire at various dates prior to October 25, 2012.

The following tables summarize information about the Unit Option Plan as at December 31, 2007 and 2006:

	2007		2006	
	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, beginning of year	582,000	\$ 8.08	419,250	\$ 7.94
Granted	27,000	9.29	202,500	8.26
Exercised	(35,750)	7.39	(20,000)	6.61
Expired	(40,500)	9.22	(19,750)	8.52
Outstanding, end of year	532,750	\$ 8.10	582,000	\$ 8.08
Exercisable, end of year	432,125	\$ 8.06	256,875	\$ 7.79

Exercise Price	Number Outstanding	Number Exercisable	Weighted Average Remaining Life (years)
\$ 4.85	20,000	20,000	0.4
5.98	21,500	21,500	0.9
7.81	36,750	36,750	1.9
8.05	146,000	146,000	2.9
8.15	183,750	91,875	3.8
8.43	20,000	20,000	2.0
9.10	74,250	74,250	2.4
9.20	7,000	—	4.4
9.32	20,000	20,000	4.8
9.79	3,500	1,750	3.7
\$ 4.85 to \$ 9.79	532,750	432,125	3.0

The various employees and directors of the General Partner, excluding officers, were granted 27,000 options on various dates during the year ended December 31, 2007 with an average strike of \$9.29 per option. The strike price of the option is equal to the market closing price of the Partnership units the day prior to being granted. At the date of granting, the options issued in 2007 had a combined estimated fair value of \$26,000. The estimated weighted-average fair value of these options was \$0.95 per option based on the Black-Scholes option pricing methodology, based on an average risk-free interest rate of 4 percent, an average dividend yield of 8.1 percent, a five-year maturity and an average volatility factor of 25 percent.

The various employees of the General Partner, excluding officers, were granted 202,500 options on various dates during the year ended December 31, 2006 at strike prices ranging from \$8.15 to \$9.79 per option. The strike price of the option is equal to the market closing price of the Partnership units the day prior to being granted. At the date of granting, the options issued in 2006 had a combined estimated fair value of \$0.2 million, which will be recognized in income over the two-year vesting period. The estimated weighted-average fair value of these options was \$0.87 per option based on the Black-Scholes option pricing methodology, using an expected risk-free interest rate of 6 percent, an average dividend yield of 9 percent, a five-year maturity and an average volatility factor of 25 percent.

Compensation expense for the year ending December 31, 2007 related to the granting of options issued since 2004 was \$0.2 million (2006 – \$0.2 million).

12. Long-term Incentive Program

The Partnership provides a portion of the compensation to the General Partner's officers, directors and certain employees in the form of Restricted Share Units ("RSUs") awarded under the Long-term Incentive Plan ("LTIP"). The LTIP is governed by a plan document that defines how awards made under the plan will be determined and administered. Under the plan, RSUs are granted to individuals effective January 1 of the year following the just-completed fiscal year and vest over a three-year period; one third of the RSU award vesting per year. Upon vesting, the holder of RSUs receives cash equal to the volume-weighted market price of Partnership units for the ten trading days preceding the vesting date times the number of RSUs that have vested. From the effective date of the RSU award, the holder of RSUs receives additional RSUs equal to the cash distributions that would be paid on the number of Partnership units that the RSUs held represent.

The annual pool of RSUs eligible to be awarded is based on a calculation that considers distributions per unit and total unitholder return benchmarked against the total unitholder return of a basket of peers and certain related indices over one, two and three years. Total unitholder return is the sum of distributions and the change in the market price of units over the specific periods.

	Number of Restricted Share Units (RSUs)
Balance, December 31, 2005	—
Awarded during the year	135,397
RSUs received in lieu of distributions during the year	10,080
Forfeited during the year	(922)
Balance, December 31, 2006	144,555
Awarded during the year	409,323
RSUs received in lieu of distributions during the year	42,924
Exercised during the year	(48,185)
Cancelled during the year	(5,356)
Balance, December 31, 2007	543,261

The compensation cost recorded for Restricted Share Units for the year ended December 31, 2007 was \$3.6 million (2006 – \$0.8 million) based on the closing market price of \$11.18 per Partnership unit.

In January 2008, 598,367 RSUs were awarded for 2007 performance that had a fair value of \$6.7 million based on the December 31, 2007 closing Partnership unit price.

13. Income per Partnership Unit

The following table summarizes the computation of net income per Partnership unit:

	2007	2006
Numerator:		
Numerator for basic income (loss) per unit	\$ (42,133)	\$ 28,726
Convertible debentures interest	2,920	2,923
Accretion of convertible debentures discount	417	417
Numerator for diluted income (loss) per unit	\$ (38,796)	\$ 32,066
Denominator:		
Weighted-average number of units	42,715,900	42,548,216
Convertible debentures	4,698,391	4,828,019
Dilutive unit options	74,826	75,944
Denominator for diluted income per unit	47,489,117	47,452,179
Basic income (loss) per unit	\$ (0.99)	\$ 0.68
Diluted income (loss) per unit	\$ (0.99)	\$ 0.68

14. Pension Plan and Post-retirement Benefits

The Partnership has a pension plan covering its unionized employees at the Younger Extraction Plant (the "Younger Plan"). The Younger Plan provides employee pensions based on length of service and the highest consecutive three years' average earnings. The Partnership has a pension plan covering certain employees at the Harmattan Complex (the "Harmattan Plan"). The Harmattan Plan provides an employee pension to existing members based on length of service and highest consecutive three years' average earnings.

The Younger Plan and the Harmattan Plan (collectively called the "Plans") rely on actuarial reports, prepared by an independent actuary, for funding and accounting purposes. The cost of pension benefits earned is determined using the projected benefit method pro-rated on employment service and management's best estimate of expected plan investment performance, salary escalation and retirement date. Plan assets are

valued at fair market value. The excess of the net actuarial gain (or loss) over 10 percent of the greater of the accrued benefit obligation and the market value of plan assets at the beginning of the period is amortized over the expected average remaining service period of the active employee ("EARSL"). Past service costs are also amortized over EARSL.

The following significant actuarial assumptions were used to determine pension cost:

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Discount rate, January 1	5.25%	5.25%	5.25%	5.25%
Discount rate, December 31	5.50%	5.50%	5.25%	5.25%
Expected long-term rate of return	6.00%	6.00%	6.00%	6.00%
Rate of compensation increase	3.50%	3.50%	2.75%	2.75%
EARSL, January 1	24.6 years	8.1 years	25.7 years	8.4 years

The funding actuarial valuation of the Plans was performed as at December 31, 2006. The next funding actuarial valuations for the Plans will be performed no later than as at December 31, 2007.

The determination of the pension cost for the Company's defined benefit pension plans is as follows:

Pension cost incurred

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Current service cost	\$ 166	\$ 180	\$ 172	\$ 189
Interest cost on accrued benefit obligation	118	331	113	281
Less actual return on plan assets	(16)	(20)	(238)	(454)
Actuarial loss (gain) during year	392	75	(211)	565
Pension cost incurred during year, before adjustments	\$ 660	\$ 566	\$ (164)	\$ 581

Pension cost recognized

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Pension cost incurred	\$ 660	\$ 566	\$ (164)	\$ 581
Adjustments to reflect long-term nature of pension plan:				
Difference between expected and actual return on plan assets	(131)	(311)	115	185
Difference between actuarial (gain) loss recognized for year and actual actuarial (gain) loss on accrued benefit obligation	(393)	(37)	211	(562)
Amortization of transitional (asset) obligation	1	(1)	1	(1)
Pension cost recognized during year	\$ 137	\$ 217	\$ 163	\$ 203

Components of pension cost

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Current service cost	\$ 166	\$ 180	\$ 172	\$ 189
Interest cost on accrued benefit obligation	118	331	113	281
Expected return on plan assets	(147)	(331)	(123)	(269)
Amortization of transitional (asset) obligation	1	(1)	1	(1)
Amortization of net actuarial (gains) losses	(1)	38	-	3
Pension cost recognized during year	\$ 137	\$ 217	\$ 163	\$ 203

Reconciliation of accrued benefit obligation

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Accrued benefit obligation, beginning of year	\$ 2,164	\$ 6,263	\$ 2,037	\$ 5,299
Current service cost (including employee contributions)	251	180	254	189
Interest on accrued benefit obligation	118	331	113	281
Actuarial loss (gain) during year	392	75	(211)	565
Benefits paid during year	(84)	(98)	(29)	(71)
Accrued benefit obligation, end of year	\$ 2,841	\$ 6,751	\$ 2,164	\$ 6,263

Reconciliation of fair value of plan assets

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Estimated fair value of plan assets, beginning of year	\$ 2,390	\$ 5,256	\$ 1,949	\$ 4,157
Partnership contributions during year	132	612	151	716
Member contributions during year	85	-	81	-
Benefit payments during year	(84)	(98)	(29)	(71)
Actual return on plan assets	17	20	238	454
Fair value of plan assets, end of year	\$ 2,540	\$ 5,790	\$ 2,390	\$ 5,256

The assets of the Plans are held by Sun Life. The assets are valued as at December 31, 2007 as reported by Sun Life.

The assets are invested under a balanced fund mandate with a broad mix of fixed income, Canadian equity and foreign equity investments. The investment mixes for each of the Plans are as follows as at December 31, 2007:

	Younger Plan	Harmattan Plan
Cash and short-term equivalents	9.4%	16.6%
Canadian equities	31.0%	28.1%
Foreign equities	28.5%	26.4%
Fixed income	31.1%	28.9%
Total	100.0%	100.0%

Determination of accrued benefit asset (liability)

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Accrued benefit asset (liability), beginning of year	\$ (6)	\$ (87)	\$ 6	\$ (600)
Plus contributions during year	132	612	151	716
Less pension cost for the year	(137)	(217)	(163)	(203)
Accrued benefit asset (liability), end of year	\$ (11)	\$ 308	\$ (6)	\$ (87)

Funded status and reconciliation of accrued benefit asset (liability)

	2007		2006	
	Younger Plan	Harmattan Plan	Younger Plan	Harmattan Plan
Accrued benefit obligation, end of year	\$ (2,841)	\$ (6,751)	\$ (2,164)	\$ (6,263)
Fair value of plan assets, end of year	2,540	5,790	2,390	5,256
Funded status	\$ (301)	\$ (961)	\$ 226	\$ (1,007)
Unamortized transitional obligation (asset)	25	(9)	26	(10)
Unamortized net actuarial loss (gain)	265	1,278	(258)	930
Accrued benefit asset (liability), end of year	\$ (11)	\$ 308	\$ (6)	\$ (87)

In addition to pension benefits, the Partnership provides post-retirement benefits for its unionized employees at the Younger Extraction Plant and employees at the Harmattan Complex. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums. For the year ended December 31, 2007, the Partnership has recorded an employee future benefits expense of \$0.1 million (2006 – \$0.1 million) and accrued the obligation in accounts payable and accrued liabilities.

15. Supplementary Cash Flow Information

The change in non-cash working capital from operations was comprised of:

	2007	2006
Accounts receivable	\$ (3,843)	\$ (7,336)
Accounts payable and accrued liabilities	1,350	3,801
Prepaid expenses and interest	231	(42)
	\$ (2,262)	\$ (3,577)

The change in non-cash working capital from investments was comprised of:

	2007	2006
Accounts payable and accrued liabilities	\$ 6,401	\$ 407

Cash interest paid for the year ended December 31, 2007 was \$8.4 million (2006 – \$8.2 million).

16. Commitments

The Partnership is committed to various lease payments for land, office space, vehicles and office equipment. Under the terms of the leases, the following future payments are required:

2008	\$	489
2009	\$	368
2010	\$	313
2011	\$	277
2012	\$	95

17. Financial Instruments

The Partnership records the settlement of financial instrument and the changes in the mark-to-market in earnings, which are aggregated in financial instruments (gains) losses, as noted below. The fair value of financial instruments are separated into assets and liabilities, and subsequently split into their current and long-term portions, as noted below.

	2007		2006	
Financial instruments gains (losses):				
Realized	\$	(1,260)	\$	620
Unrealized		(4,638)		215
	\$	(5,898)	\$	835
Balance sheet classification:				
Assets:				
Current, included in accounts receivable	\$	575	\$	732
Long-term		—		663
	\$	575	\$	1,395
Liabilities:				
Current, included in accounts payable and accrued liabilities	\$	4,032	\$	32
Long-term		24		207
	\$	4,056	\$	239
Total fair value of financial instruments	\$	(3,481)	\$	1,156

Interest rates

The Partnership has fixed the interest rate on \$70.0 million of its bank debt using interest rate swaps. The fair value of the interest rate swaps recorded on the balance sheet and changes in the mark-to-market ("MTM") recorded in earnings are summarized as follows:

				2007		2006	
Principal	Fixed Rate	Start	End	Fair Value Asset (Liability)	MTM Change Gain (Loss)	Fair Value Asset (Liability)	MTM Change Gain (Loss)
\$ 10,000	4.130%	Feb. 22, 2006	Jan. 31, 2007	\$ —	\$ (5)	\$ 5	\$ 5
10,000	4.195%	Jan. 31, 2007	Jan. 31, 2008	13	5	8	8
20,000	4.150%	Jan. 2, 2007	Jan. 2, 2009	49	17	32	32
20,000	4.410%	Feb. 1, 2005	Feb. 1, 2010	(86)	55	(141)	110
20,000	4.335%	Feb. 22, 2006	Mar. 1, 2010	(58)	40	(98)	(98)
				\$ (82)	\$ 112	\$ (194)	\$ 57

The Partnership and the providers of the interest rate swaps have early settlement options, in whole or in part, of the principal amount, which are currently in effect and exist until the maturity date. If either party exercises this option, the derivative financial instrument will be settled at the then current market price.

Electricity rates

On October 11, 2005, the Partnership entered into electricity rate swaps for 3.5 MW, whereby the Partnership receives a floating rate and pays a fixed rate. For the one-year period commencing January 1, 2008, the Partnership will pay a fixed rate of \$56.50 per MWh. The fair value of the electricity rate swaps at December 31, 2007, based on the then current market price, was an unrealized asset of \$0.6 million (2006 – \$1.4 million). The change in fair value during 2007 was recognized as a mark-to-market financial instrument loss of \$0.8 million (2006 – \$0.2 million gain). The Partnership and the provider of the electricity rate swaps have early settlement options, in whole or in part, of the contract amount, which are currently in effect and exist until the maturity date. If either party exercises this option, the derivative financial instrument will be settled at the then current market price.

NGL margin

On July 10, 2007, the Partnership entered into a series of swaps that have the effect of fixing the natural gas liquids margin at approximately \$15.50 per barrel on 20,700 barrels of propane-plus natural gas liquids per month. The swap arrangements commence August 1, 2007 and expire December 31, 2008. Taylor has used the fair value method for reporting the natural gas liquids margin swap.

The NGL margin swap that was entered into on July 10, 2007 is comprised of:

	Price	Quantity per month
Sell:		
Propane (Mt. Belvieu)	\$1.185 per US gallon	14,000 barrels
Normal butane (Mt. Belvieu)	\$1.370 per US gallon	3,300 barrels
Iso-butane (Mt. Belvieu)	\$1.410 per US gallon	1,400 barrels
Condensate (WTI)	\$77.09 per barrel	2,000 barrels
Buy:		
Natural gas (AECO)	\$6.95 per GJ	88,200 GJ

On November 26, 2007, the Partnership entered into a series of swaps that have the effect of fixing the natural gas liquids margin at approximately \$26.00 per barrel on 21,000 barrels of propane-plus natural gas liquids per month. The swap arrangements will commence April 1, 2008 and expire December 31, 2008. Taylor has used the fair value method for reporting the natural gas liquids margin swap.

The NGL margin swap that was entered into on November 26, 2007 is comprised of:

	Price	Quantity per month
Sell:		
Propane (Mt. Belvieu)	\$1.39 per US gallon	14,000 barrels
Normal butane (Mt. Belvieu)	\$1.57 per US gallon	3,500 barrels
Iso-butane (Mt. Belvieu)	\$1.6125 per US gallon	1,500 barrels
Condensate (WTI)	\$90.05 per barrel	2,000 barrels
Buy:		
Natural gas (AECO)	\$6.69 per GJ	89,600 GJ

The combined fair value of the NGL margin swaps at December 31, 2007 was an unrealized liability of \$4.0 million, which was recognized as a mark-to-market financial instrument loss for the year ended December 31, 2007.

The NGL margin swap has early settlement options, in whole or in part, which are currently in effect and exist until their respective maturity date. If either party exercises this option, the derivative financial instrument will be settled at the then current market price.

Fair value of derivative financial instruments

END

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and Unitholders' distributions payable approximate their fair values due to the near term nature of these financial instruments. The carrying value of long-term debt approximates fair value as it bears interest at floating rates.

Credit risk

A significant portion of revenue from the Younger Extraction Plant is received from a single customer under the NGL Purchase Agreement and other joint venture agreements. In addition, a significant portion of the Partnership's revenue originates from commercial arrangements with another customer through the sale of ethane from the Joffre Extraction Plant, the EDS and JFP transportation agreements and the sale of the Partnership's share of Harmattan Complex ethane.

In the event that these two customers are unable to fulfill the obligations under these various agreements, the Partnership's net income may be significantly negatively affected. At December 31, 2007, the accounts receivable from these two customers amounted to approximately 77 percent (2006 – 74 percent) of the accounts receivable including shrinkage gas, which represents 41 percent of the year end balance (2006 – 51 percent). For the year ended December 31, 2007, 36 percent (2006 – 28 percent) of the Partnership's NGL sales and fee income less shrinkage gas, operating costs and overhead recovery fees was earned from one customer. For the year ended December 31, 2007, 29 percent (2006 – 32 percent) of the Partnership's NGL sales and fee income less shrinkage gas, operating costs and overhead recovery fees was earned from the other customer.

The RET Complex and Harmattan Complex have credit exposure to a number of customers in the oil and gas industry under their operating and processing arrangements. These amounts are subject to normal industry credit risks.

18. Guarantees

The Partnership has entered into an agreement indemnifying a third party with respect to potential third party claims, such as environmental and tax, associated with the acquisition of the RET Complex in 2003. Due to the nature of the indemnifications, the maximum exposure under the agreement cannot be estimated. As at December 31, 2007, management has not been notified of any claims.

Upon the acquisition of the Harmattan Complex, the Partnership assumed performance guarantees with respect to the operation of the facility under the terms of the Representation, Management and Processing Agreements (the "Rep Agreements"). Currently, approximately 50 percent of the natural gas volume processed at the Harmattan Complex is subject to the terms of the Rep Agreements. If the guaranteed processing requirements cannot be met, the Partnership will be subject to penalties that could have an adverse effect on the Partnership's results. No penalties have been incurred by the Partnership since it acquired the Harmattan Complex.

19. Insurance Claims and Contingencies

On March 8, 2007, the Partnership was advised that the remaining claim for \$5.8 million against several parties, including the Partnership, with respect to the 1999 outage at the Younger Extraction Plant, expired with no action by the claimant. As a result, the Partnership has resolved all claims and litigation actions with respect to the 1999 outage.

The Canada Revenue Agency ("CRA") submitted a Goods and Services Tax ("GST") reassessment for the period October 2002 to September 2005 for \$1.2 million. The reassessment relates to claims for Input Tax Credits made by the Partnership for GST paid in the course of obtaining goods and services for the operation of its businesses. The CRA asserts that the Partnership does not carry on commercial activities, as defined in the Excise Tax Act, and is therefore not allowed to claim Input Tax Credits. Since September 2005, the Partnership has claimed approximately \$0.4 million (to December 31, 2006 – \$0.3 million) in Input Tax Credits that are similar to those being challenged by the CRA. The Partnership has obtained legal advice and has submitted to the CRA a written Notice of Objection supporting the Partnership's position that the Input Tax Credits have been properly claimed in accordance with the law. Accordingly, the Partnership has not expensed the proposed reassessment, interest or penalties in its financial statements.

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