

**AltaGas Investor Day
November 2006
Transcription**

Debbie Stein:

Good afternoon, ladies and gentlemen and welcome to AltaGas' first Investor Day here in Toronto. For those of you who I have not met, I'm Debbie Stein, Vice President Controller. With me today from our Investor Relations Group is Manager IR, Stephanie Labowka-Poulin and our newest member of the IR team, Sheena McKellar. So please feel free to approach anyone of us if you need any further information or if we can help out in any way.

I'd also like to welcome our staff from our Burlington office who were kind enough to come out to help us today, and thank our staff back in Calgary, who helped us planning this event.

Upon registration, you would have received a booklet with today's presentations, together with our Third Quarter results issued last week. And we've also included the bios of members of our executive team, some of whom are presenting here today, in addition to a copy of our core values that David will talk about later.

Our agenda for the afternoon will begin with David Cornhill, our Chairman, President and Chief Executive Officer, who will discuss our strategy and business model. Jim Bracken, Senior Vice-President, Energy Services and Power, will discuss Power and Energy Services. Followed by Marshal Thompson, Senior Vice-President, Gathering and Processing. Marshal will discuss what's going on in Extraction and Transmission as well as the FG&P segment.

After a short break, Richard Alexander, Senior Vice President and Chief Financial Officer will talk about our growth strategy and our financial strategy and David will then wrap up with a few closing remarks.

We'll have time for Q&A's after each of Jim's, Marshal's and Rick's presentations and David's wrap up at the end. We hope to finish the formal part of the afternoon at 4:30, at which time we will be hosting a reception in the mezzanine lounge, up the stairs from the hotel reception area, where you'll have a further opportunity to meet with the management team.

Other members of that team here today are Nancy Anderson, our VP Business Development, Nancy? Dennis Dawson, Vice President, General Counsel and Corporate Secretary, Patricia Newson, Senior Vice President and Kent Stout, Vice President of Corporate Resources.

Also with us today, are Bill Swan, Max Fantuz and Mike Kilby, the management team of our Energy Services business here in Ontario. We're glad to have the Ontario team here with us.

On an administrative note, we are being webcast live. So we ask that you raise your hand when you would like to ask a question and Stephanie or Sheena will bring you a microphone. If you could identify yourself and your organization before posing your question, that would be very helpful.

I would like to draw your attention to our forward-looking statements on the first page of the presentation tab and remind you that our presentations and discussions today may include forward-looking statements. Such statements reflect the Trust's expectations, estimates, projections and assumptions. The statements are not guarantees of future performance and are subject to certain risks that could cause actual performance in financial results in the future to vary materially from those contemplated in the forward-looking statements.

And with that, I am now very pleased to turn the proceedings over to Mr. David Cornhill, Chairman, President and Chief Executive Officer of AltaGas Income Trust. Thank you.

David Cornhill:

Thank you very much and it's a pleasure for me to be here today at the first Investor Day. It's also very nice that I have to do a very little speaking today and you'll have the benefit of hearing this team present today. And as I can tell you how little involvement I have, I'm not sure how to change the slides so just bear with me. Which? This one? That one? Okay. Great. Thanks Jim.

Thank you for joining us today and I'm happy that we can provide the opportunity to talk about AltaGas' business. And meet many of the executive team here and look forward to later to have question and answer.

Let me start by giving you the context within which we operate at AltaGas by sharing our vision, which is to be the leading Canadian integrated energy infra-structure organization. And the integrated is a key part of our business and we'll be talking about that today. We will do so by capitalizing on a solid underlying business, operational expertise and financial strength. We have a proven track record of success and we believe that we are well positioned to pursue our vision.

Our business model is to create, operate and grow our integrated midstream energy business. We own and operate physical assets and deliver time-sensitive, essential services to customers, which produce or consume energy. We have here our four operating business segments: Field Gathering and Processing, Transmission, Power and Energy Services. Our business segment mix will continue to shift over time.

When we started the business in 1994, the major source of operating income was our Energy Services business followed by Extraction and Transmission. By the year 2000, Field Gathering and Processing provided the majority of the operating income of the company, with Extraction and Transmission and Energy Services providing smaller amounts.

Today, you'll see after the third quarter this year, our Power segment provides a large portion of our operating income, followed by Extraction and Transmission, then Field Gathering and Processing and Energy Services. We grow where we see the best value but the key is the integration of our business.

This slide shows the enterprise value from 2001 to September 30th of this year. At September 30th, we had enterprise value of \$1.8 billion, it's gone down a little bit with the recent announcement, we're down about 10% since the announcement of the new tax changes on enterprise value.

Key point of our growth strategy is to have investments that have meaningful linkages to our existing businesses. Investments that are created from our earnings and cash flow. We've always focused on earnings and it's still a key part of our business and more important today. Well, I'm not sure it's more important but it's become more popular today than it was in September. Investments that have attractive risk return, compared to alternatives and investments that maintain our risk balance.

When we look at our strategy on a day-to-day, what does it mean? It means that we need to do detailed, in depth, real-time financial analysis to monitor performance. We have to be rigorous about our operating discipline, to identify value creation levers and options to adjust to improve performance. And our execution of operating discipline requires continuing optimization of ongoing operations, achievement of financial targets, which are critical on our organization, and living the core values of AltaGas.

Our number one core value that's on our planning metrics every quarter is safety and environment, and I can tell you that we do think safety is the most important because we have a number of people that go out everyday. It's critical for them to come home at night, in the field.

On a net income basis, EBITDA, these are from 2000 to the trailing 12 months, September 30th '06 on a per share basis, you can see EBITDA has grown by 53%, net income has climbed by 234% and funds generated from operation over this time has increased by 31%.

ROE has always been important to us. It's been part of our performance measures from day one and we think it's a very important measure and I think this graph speaks for itself.

This is a very interesting graph. This shows the integration of our business and monetizes linkages within our business. You can see here--I'll just quickly walk through it, I don't--there will be a test later on this, but some people wonder how our business works. Our Energy Services business through our Extraction and Transmission, \$4 million, for about 25 Bcf of transmission capacity on pipelines. Our Extraction and Transmission to our Energy Services, about \$240 million for the purchase for the 30 Bcf of gas that goes through--shipped through our extraction plants. Extraction and Transmission to Energy Services for about five Bcf of gas provided for extraction shrinkage; Extraction and Transmission to our Power \$9 million, for 18 megawatts of power consumption. Field Gathering and Processing, about \$6 million, for 10 megawatts of power consumption; Energy Services to Power about \$25 million, for 40 megawatts of supply to end-use customers. Power to Energy Services about \$8 million for a Bcf of gas, for a peaking plant's supply. Energy Services to Field Gathering and Processing about \$240 million for about 30 DCF of gas that we market for producers, and that's a key credit mitigate for Field Gathering and Processing. And Energy Services to Field Gathering and Processing, about \$2 million to processing of fees on our oil and gas production.

Clearly you can see we're one business and the linkages do work at AltaGas.

And finally, just showing the September 30th numbers EBITDA, we announced \$128.6 million for the first nine months of 2006, of that Power contributed 49%, Field Gathering and Processing 24%, Extraction and Transmission 23%, and Energy Services 4%.

And that wraps up my presentation until the closing remarks, and now I'd like to pass it off to Jim Bracken to start on the Power Generation. Thank you.

Jim Bracken:

Thank you, David. Good afternoon. I'm going to speak about the Power Generation segment, and then about the Energy Services segment, and leave some time after that for questions, if you have any, on both of these segments.

So, start at first with Power. Our Power Generation segment does four things primarily. We manage the current generating assets that we own. In other words, we manage the contractual arrangements that we have in place, and we engage in dispatching strategies for those facilities. The second thing we do is execute hedges; we sell power forward in the financial market. The third thing is that we supply power for

other segments of the business, and that includes power for consumption in some of our operations, Extraction, and Transmission, and Field Gathering and Processing, as well as power for resale of the Energy Management business. And I'll come back to those later. And then the fourth thing is that, we are developing the Bear Mountain Wind Project, and I'll speak some more about that. This is the first Power project that we've initiated from the development stage, and we expect to see more coming in the future, and Rick will talk a little bit more about that in the Growth Strategies.

I'll speak first a little bit about some of our current generating assets. Our single largest power asset is our contractual rights to Sundance B plant in Alberta. We own 50% of Sundance B, and our ownership interest consists in particular of units three and four, of the six units on the site. We acquired this in 2001, and the contract continues until 2020.

Our ownership rights are contractually structured in the PPA, or Power Purchase Agreement, and I'm going to talk a little bit about some of the terms of that agreement, for those of you who are less familiar.

The plant itself is two 353-megawatt coal-fired generators and they are among the lowest cost power generators in Alberta. The units are owned and operated by TransAlta, and TransAlta plans to expand by 53 megawatts on this site in 2007, and we do have some contractual rights to the additional revenue that will come from that expansion.

Sundance B is structured, as I mentioned contractually under the Power Purchase Agreement, the PPA, and our contractual rights provide for a very high degree of predictability in the costs that we incur under this. We pay fixed monthly capacity payments, which are based on predefined price indexes. We pay for coal costs based on a formula and indexes, not the actual cost; those costs are incurred by TransAlta. But based on a formula-driven index, we pay for the equivalent of the coal cost.

And then, we are also responsible for any potential changes in law although there are provisions in the PPA for us to be able to terminate the arrangement if those kinds of costs cause the contract to be unprofitable. So, you can see the costs that are structured in this PPA are highly predictable.

The PPA is also designed to create incentives for the operator, TransAlta, to produce electricity at pre-established levels. This is structured through the availability incentive payments for the actual generation. Any actual generation above the targeted capacity, AltaGas pays TransAlta the 30-day Rolling Average Power Price or what we affectionately know as RAPP. Below the targeted capacity, TransAlta pays AltaGas that RAPP. And the

target capacity on this is 86% of the rated capacity. So you can see these availability incentive payments significantly reduce our exposure to scheduled or unscheduled outages.

The other significant current generating assets we have are our gas-fired peaking plants. We own the rights to these through long-term capital lease. The assets consist of 25, one-megawatt reciprocating engines located in Southern Alberta. We earn revenues from these through sale of energy as well as through the sale of ancillary services. These are very fast-ramping units, we could actually bring these things up in response to power prices within 10 minutes.

They also, in addition to being able to generate revenue for us from energy and ancillary sales, they provide some backstopping to any potential outages on the Sundance unit. That helps us a lot because it eliminates or reduces the need for us to sell capacity off of Sundance on a unit contingent basis so that improves our revenue on the Sundance asset.

We've had a very good year so far this year with these peaking plants. They've run a great deal. We've seen a lot of high and spiky prices in July and again in October. And we'll continue to see those kind of high and volatile prices in Alberta.

Since acquiring the Sundance power contract, we've maintained a consistent and highly disciplined hedging strategy. And this hedging strategy allows us to maintain stable earnings. We do not engage in any speculative trading. We are not a trading shop. We focus on 12 to 24 months forward using financial swaps with investment-grade counterparties. We will also occasionally enter into costless collars or unit contingent sales and reciprocal backstopping arrangements with other generators. And included in our hedging is over 50 megawatts of supply for internal operations and for Energy Services end use customers.

We remain very bullish on the Alberta power price. And here are some of the facts on this slide that support our bullishness. The NERC, the North American Energy Council, has indicated that current reserve levels are below minimum targeted levels and that will continue to be so for the next two or three years, at least. The Alberta MSA has indicated that the recent high prices in Alberta are a clear signal to build, however, transmission constraints are likely to prevent major new generation in Alberta until at least 2009.

The AESO is forecasting demand increases of 2.7% a year or the equivalent of about 215 megawatts a year. That's the equivalent of a half of a large coal generating plant. We're also expecting to see several large coal units being retired over the next few years. This slide is from the AESO site, and it shows graphically what some of the demand increases and expected

retirements look like over the next few years. In effect, what this is saying is that growth and expected retirements are likely to create outages and keep prices relatively high.

Turning now to some of our growth prospect in Power, the Bear Mountain Wind Farm is something we've announced recently as the strategic growth opportunity in renewable energy. As you may know from some of our announcements, the Bear Mountain Wind Farm is 120 megawatt wind farm located in the Peace Region of Northeast British Columbia, but that particular region, the Peace Region, is purported to have about 85% of the wind resource in British Columbia. In this project we've partnered with Aeolis Wind Power Corporation to form a limited partnership, and we are seeking further strategic partners in this project.

The Bear Mountain Wind Project has executed a 25-year electricity purchase agreement with BC Hydro and the project has received approval from the BCUC. We have an agreement in place with Enercon, which is a leading German wind turbine supplier to supply direct 60 E82 turbines and to provide a long-term operating and maintenance agreement for those turbines on the site. We're currently in the process of negotiating the final details of the energy procurement and construction contract with Enercon and I would like to mention that somebody there's a-- Enercon is highly regarded as one of the premiere suppliers of turbines and there's something unique about their turbines in that they are gearless. They do not include a gearbox. That's a fairly unique technology that will significantly reduce operating and maintenance costs and extend the life of those turbines.

This next slide is a photograph of the Bear Mountain Wind site. It's a picture looking east. You might be able to see across the ridge a number of turbines. I think there are about 18 of them in this picture. This is a bit of Photoshop license, in that we haven't actually built these turbines yet but this is what they will look like across the ridge. And this is just the north section. As I mentioned, there will be 60 turbines along this ridge.

So, in conclusion our power outlook for the Power Generation segment is to see continued strong power prices in Alberta to maintain an increased earnings from both current assets that I was talking about. Our continued discipline hedging strategies will continue to provide earning stability. Sales of power to energy management customers, actually helps provide additional length to our hedge book. And the Bear Mountain Wind Project will add earnings starting in 2009.

I'm going to move on to Energy Services now. The Energy Services segment is made up of three components: energy management, gas services, and oil and gas production. And I'm

going to speak a little bit about the first two of these components, energy management and gas services, as well as how they interrelate. I'm not going to discuss the production business because it's not core to our operations. These are production reserves that we've acquired over time in conjunction with other midstream assets.

The Energy Services segment generates low-risk earnings. We are not a trading shop and we do not take open positions or expose ourselves to price risk. It's primarily a service business. It's not capital intensive. The services enhance the value and use of our other assets across AltaGas but are not themselves capital intensive. We use people, expertise, industry knowledge and contracting capabilities, and processes to drive this business.

The business is based on long-term contracts, which create stable future earnings. They have the agency business contracts for one to three and in some cases up to eight years. And most of those contracts are evergreening, and in the gas services business, we have been entering into contracts of three and even five years in length. There is some organic growth in this business. We are adding customers, adding services to existing customers without capital spending.

I'll turn now to the energy management component within the Energy Services segment. This is really the retail agency services part of our business. Just to provide a quick overview of it here on this slide, it's a fee for service business. In this business, we manage and procure gas and electricity for end-users under agency arrangements. We provide independent advice on price trends and offer contracting and balancing expertise to end-use customers. The customers are typically small, industrial, commercial, institutional and agricultural customers. We're not in the residential market. I thought I would take a minute to describe here how the energy management business is actually conducted.

AltaGas, primarily under the ECNG name, makes arrangements with suppliers on behalf of customers but does not take title to the energy supply. In most cases, the billing is done through utilities giving customers a single bill and supply price. Customers benefit from our expertise and advice on contracting and balancing, and they reduce their price volatility, in other words, they manage their risk appetite relative to energy prices. The agency agreements are one to three years evergreening and we've actually entered into some for five and even eight years in term.

With respect to the marketplace for energy management services, we currently operate as ECNG in Ontario and East as iQ2 in Alberta and as PremStar Pacific in British Columbia. And starting in January of 2007, we will be announcing and

operating under a single national brand, and that national brand will be ECNG Energy. We have over 2,000 customers. In fact, when we look to end use sites or locations, it's probably over 10,000 in total. Our customers include hospitals, schools, municipalities, manufacturers, retailers, property managers and agricultural businesses. And I'll just give you an idea of some of the customers we have by mentioning a few names. In the hospitals category, we serve HealthPro here in Ontario, which is an association of government-funded hospitals and medical clinics. In the schools category, we supply the Waterloo School Boards in Ontario and 13 school districts and colleges in British Columbia. Under the municipalities category, we serve the City of Kitchener. And under the manufacturing sector, we service Cobacor, Scott Paper, Molsons, Toyota, Honda, Firestone, Camby, and HJ Heinz. Some of the retailers we service are the Motor Dealers Association of Alberta and the Canadian Tire Dealers Association here in Ontario. Under the property category, we service Brookfield, FRPO, F-R-P-O, the Federation of Retail Property Operators in Ontario, and CHIP Hotels and Coast Hotels across the country. In the agricultural sector, we service the Hutterite Colonies in Alberta, the Alberta Livestock Producers, Cargill and Olymel in Alberta. So that just gives you a sense for some of the energy management customers that we serve.

Switching now to the other component of the Energy Services segment, gas services. This slide gives a quick overview of the services that we provide. The main one is buying and reselling gas for energy management end-use customers. In this business, we do take title to gas from large wholesalers and we make back-to-back sales to end-use customers. So that locks in margins at the time of the contracting. The terms for these contracts can be up to five years, and as you can see there's a high degree of synergy here with the energy management business. In addition to the buying and selling of gas, we also exchange gas and deliveries of gas at connections along our transmission pipelines, and we market gas for a few gathering and processing producers in Alberta.

Although gas services requires no capital in terms of infrastructure spending, it is somewhat credit intensive. We manage our credit risk very carefully. First of all, all of our offerings, as I've mentioned, are fixed price. So, we do not do any speculative trading and we do not take any price risk in this business. We do manage the credit exposure on buying and selling customers by performing credit checks both on customers and on suppliers on both sides of these deals, and by limiting and tracking exposures to certain segments.

This is a pictorial of some of the integration across AltaGas and you saw this same picture in David's presentation. In his slide, he was talking about the dollars of activity among the different segments. This slide shows the volumetric activities. And I'll

just go through this roughly starting at the top and going clockwise around.

Energy Services provides marketing services for about 30 billion cubic feet per year of field gathering and processing producers gas to add value and reduce credit risk. Energy Services also purchases about a billion cubic feet a year of gas for peaking power plants for the power segment. The power group supplies over 40 megawatts of power for consumption to energy management end-use customers. Energy Services also contracts 25 billion cubic feet a year of capacity and exchanges on our transmission pipeline. We also contract 30 billion cubic feet per year of gas supplies through the extraction plants and we purchase about five billion cubic feet a year of shrinkage gas for those extraction plants.

So in addition to those areas of integration with Energy Services in the other segments, I've also got on this slide the integration between Power Generation and the other segments and you can see that Power provides about 18 megawatts of power for consumption by the extraction plants, and about 10 megawatts for consumption by the field gathering and processing facilities. So as you can see from this, there's a very high degree of integration across the business units.

As I mentioned, as a services-based business, the Energy Services segment doesn't rely on capital intensity. It relies on people, skills and processes. We have significant competitive advantages, which allow us to maintain and grow this business. These competitive strengths come from the integration of PremStar, ECNG and iQ2 with AltaGas. There's a high degree of integration of the wholesale and retail services, as I've mentioned earlier, whereby gas services supplies gas to the energy management customers.

We have a very strong market reputation for service to end-users that's indicated by our very high renewal rate with customers of over 95%. We have a single electricity bill in Ontario, this a very key strategic advantage to being able to provide electricity services at the retail level in Ontario. It greatly simplifies what the customer sees on their bill and combines all of the elements in one spot. We serve multi-locations end-users across Canada and I've mentioned some of those customers. We have very strong back office support systems for customer services that allow us to track and balance gas and energy consumption, balance the difference between energy purchased and energy consumed which are key to providing services in these segments. And we have a very strong balance sheet that supports the credit requirements. This is an incredibly important factor in allowing gas services to purchase supply from investment grade wholesale suppliers.

So, how have we been doing in this sector? In 2006 year-to-date, we see some significant increases in the business year. The number of energy management customer contracts has increased 8% and the gas services volumes that we are marketing has increased 6%. So far this year, we added a large hospital association as an electricity customer in Ontario. We renewed an agreement with the major agricultural aggregation in Alberta for an eight-year term. We now provide gas services to a major Canadian brewery across three provinces and to a hotel chain across five provinces. We've added about 5,000 GJ's a day of three to five-year term buy and sell gas contracts in the gas services business.

So, in conclusion on Energy Services, our outlook for this business is continued organic growth through customer acquisitions. Particularly in the energy management business, because that business is driven off of price volatility and uncertainty, as markets become less regulated, customers need more assistance in managing their energy loads. We expect to see growth in the energy management services generating growth in the gas services business because of the high integration of these energy management customers become gas services customers. And we expect to see increased margins with the combination of gas and electricity offerings across all of our customer groups.

And that concludes my formal remarks. I'd be happy to take any questions. And Stephanie's got a microphone there for anybody that (inaudible)? Yes, Winfried?

Winfried Fruehauf: Are there any plans to assist the farmers in the bio-diesel and ethanol businesses?

Jim Bracken: No, we haven't got any plans with that particular sector at this stage.

Winfried Fruehauf: Why not?

Jim Bracken: That's not an area that we feel that we have any strong expertise in at this stage. Linda?

Linda Ezergailis: Thanks. I don't think--oh, this is on. Just a follow up question with respect to your Sundance PPA arrangement, my understanding is that TransAlta views the 53 megawatts upgrade as 100% merchant. Have you had any discussions with TransAlta directly or the Power Pool Administrator or anything as to their interpretation versus yours?

Jim Bracken: Well, we have had specific discussions with TransAlta, and we do, as I mentioned, have contractual rights to revenues from that uprate. That's part of the PPA arrangement. The effect that that has on us is it's the equivalent to us of having between two and three megawatts of additional capacity with no additional capital cost.

Linda Ezergailis: Do they agree to that? Because my understanding talking to them is that they view that as 100% merchant.

Jim Bracken: My understanding is they agree with our view on that. That is a definitely revenue stream that we will see.

Linda Ezergailis: Okay. And maybe while we're on the topic of Alberta power, what's the latest status on any sort of Genesee PPA auction? I'm hearing silence out of Alberta and I'm just wondering if you can give us an update on that?

Jim Bracken: That's a good question (inaudible) silence on another auction at this stage. The Genesee contract is still with the Power Pool. They're still managing that and dispatching it. There have been a couple of faulty starts on putting that back in to re-auction it. It's my view that that's being held up by some regulatory matters around market concentration. And it won't be until the regulators are comfortable with new market concentration rules, that they'll put that on to the market. So I don't expect we will see that within the next few months. It will probably take a little while for that to come back on to the market as another auction. And we'd be happy to participate in it when it does.

Dominique Barker: Did you say with Bear Mountain that you were looking for additional partners?

Jim Bracken: Yes.

Dominique Barker: Industry participants or just equity investors or?

Jim Bracken: Well, we're looking for some strategic partners that could bring something unique to it. We've got a couple of parties that we've been talking to. An industry participant would certainly fit some of those characteristics.

Dominique Barker: Okay. And have you--which is with respect to Enercon--the reason I ask this question in turbine prices have increased--I'm sure you're well aware. Have you actually negotiated the final price on the Enercon turbines or is that still--

Jim Bracken: We have a memorandum of understanding with Enercon that has a price set in it. That price is subject to a potential price index if there's a--it's an industrial price index in Germany. If the price goes beyond that, there could be a price adjustment. But at this stage, that index hasn't kicked in, so we've got, in effect, a fixed price at this stage.

Dominique Barker: Okay. And then could you just comment with respect to Alberta power prices, it's--some good color with respect to your views on power prices? What impact do you think any of the proposed transmission lines that are being proposed, I think, with the U.S.? Can you comment on the impact that might have on Alberta power prices, your view of that?

Jim Bracken: Well, yeah. That's a good question and it's something a lot of people are thinking about. Clearly, if there is more capacity into the province that provides more supply, and it starts to deal with some of the pressures that we're seeing on price. At this stage, there's not certainty around any of those transmission lines, so I'm not sure. We haven't modeled what that will do price because there is a great deal of uncertainty on those transmission lines.

Kaan Oran: Just another question on Bear Mountain. So can you remind us again why you feel Bear Mountain will be a success where so many other wind farm projects, similarly, have not been? For instance, how much data do you have--how tried and true is Enercon? I'm not familiar with them.

Jim Bracken: We're very confident about Bear Mountain being a success. The reason that we proceeded with that particular site, and our development partner does have some other sites in mind, is that this site does have more historic wind data than many sites around. There are several years of data. I don't recall off hand exactly how many years, but BC Hydro had been monitoring the site and has, I think, at least five years of wind data for four sections of that ridge already. So it's got the most historic wind data. It's got a very high degree of support by the local community, so we aren't facing some of the resistance that some communities have had to wind projects. We've actually got active support within the Dawson Creek community and among the first nations for the project. And the other key factor is Enercon. Enercon is committed to this project and is a premiere supplier. Their technology is known as being the best in the industry, and their reputation for service is among the best as well.

Kaan Oran: How much of the advancement do you have from an operating cost standpoint or from a maintenance cost standpoint? And how much more data do you have? I mean, if you were to sort of review why you think most wind projects of Canada seem to, at least the ones that we're aware of in the trust market, seem to have failed. Why do you think this is any different?

Jim Bracken: Well, I think, in part, because we're learning from some of those failures.

Kaan Oran: What have you learned?

Jim Bracken: Well, that you need to have some pretty good history on wind data and pay close attention to it and not overestimate what that resource is. I think a lot of projects have done that.

Kaan Oran: So what is your estimation with regards to Bear Mountain and in terms of expectations? Is that public?

Jim Bracken: Yeah, well, expectations with respect to what in particular?

Kaan Oran: How much wind data you'll have?

Jim Bracken: That's not in the public domain.

Kaan Oran: Have you spoken to what sort of operating cost or maintenance cost advantages that this project will have relative to other projects?

Jim Bracken: Again, that's not public, but we are finalizing those details, and we feel pretty confident. Enercon has also been a supplier to another large project in Southern Alberta, and we're getting some learnings and experience from that as well.

Winfried Fruehauf: Correct me if I'm wrong, but I understand that BC Hydro gave a PPA just to everybody who dares to raise his or her head above the breathing hole, and so I take it, and correct me please, that you have not signed a final PPA with BC Hydro, have you?

Jim Bracken: We have signed an Energy Purchase Agreement with BC Hydro, and it has been approved by the BCUC. But you are right that there were an awful lot of projects that were initially approved, and my understanding is that BC Hydro is expecting something like a 20 to 40% attrition rate among those projects. And there are some, for example, wind projects that do not yet have wind turbine suppliers locked up, and they are less likely to proceed than others.

Winfried Fruehauf: So the agreement you have, in effect, allows you to take it to the bank?

Jim Bracken: Yes, it does.

Winfried Fruehauf: Okay, thanks.

Dominique Barker: Some more question on the wind. AltaGas has talked about-- potentially; you've locked up, I don't know, that land for 1,300 megawatts, of this amount from memory, for wind power? As a potential down-the-road wind development, what's the probability of that going ahead given the large CAPEX? Does that fall off in terms of probability?

Rick Alexander: Maybe I'll answer that question. In our planning, we're assuming that about a quarter of those projects will go ahead. Those projects will all be RFP-type projects and so it's not reasonable to assume that we'll win all those RFPs or that they'll all meet our hurdle rate once they're fully developed.

Dominique Barker: Do you still expect a need for partners on that, on that one quarter?

Rick Alexander: Oh, one of the advantages of looking for a strategic partner now is that we're hopeful that as we go forward, that party can work with us in future projects as well.

Jim Bracken: Are there any other question? If not, I'll turn the microphone over to Marshal Thompson.

Marshal Thompson: Good afternoon. I'd like to give you now an overview of the Extraction and Transmission business and then the FG&P business and again, we'll answer questions at the conclusion.

Our Extraction and Transmission business involves long-life assets underpinned by long-term contracts with little commodity risk. We have interests in four of 10 Alberta extraction plants with inlet capacity of 539 million cubic feet a day. Two of these plants are at Empress, Alberta, where we own just under 200 million a day capacity. We also own 50% of the Joffre ethane extraction plant and approximately 49% of the AltaGas operated Edmonton ethane extraction facility as well as we operate a fractionation facility at Bantry, which produces specification propane, butane and condensate from NGLs produced in our field gathering and processing facility. Production at these plants average almost 20,000 barrels a day of ethane and NGLs in 2005. Gas supply for the extraction facilities comes from producers, Energy Services, customers and demand from downstream markets. All ethane production is sold under long-term arrangements based on a cost of service or fixed-fee contracts with no commodity risk while 78% of the NGLs are sold under long-term contract with no commodity price risk exposure. The remaining NGL production is capped downside exposure due to the ability to re-inject the NGLs when frac spreads are low. AltaGas also has fixed transmission pipelines with high reliability and low operating cost. The biggest is Suffield, which is underpinned with a long-term contract with EnCana up to 2022.

This is a picture of our Edmonton extraction facility, which we've operated since its acquisition in 2004. Safety of our employees, our neighbors and the environment is critical to AltaGas wherever we operate. Our safety record was recently recognized by Alberta Human Resources and Employment. We received the Work Safe Alberta 2005 Best Safety Award. Of over 128,000 employers in Alberta, only 350 received this award. Our extraction business removes ethane and NGLs remaining in the gas after field processing but before the natural gas is delivered to final consumption in end-use markets. The process most normally uses a cryogenic process, which through a series of steps uses temperature and pressure differences to remove the heavier hydrocarbons, first the NGLs then the ethane from the natural gas stream. Shrinkage gas is the term used for the gas that replaces the heating value of the ethane and NGLs removed in the process, and is the major cost of extraction. The plant is balanced on a heat-rate basis. As GJs are removed, they are replaced with more natural gas. Unlike field gathering and processing, extraction is not required in order to burn gas in the market. Operation of the plant is driven primarily by the cost of shrinkage gas and the market

demand and price for ethane and NGLs, which I'll discuss in the next couple of slides.

Ethane is used as a feedstock to create ethylene, which again is an input into a wide range of end-use products from antifreeze to shampoo and paints. The primary Alberta ethylene buyers are Dow and NovaChem for use in their ethylene plants at Fort Saskatchewan and Joffre respectively. Alberta has the lowest cost ethylene feedstock in North America, primarily due to the cost of the gas. Likewise, NGLs are further processed, fractionated into their components: propane, butane and condensate for use in residential heating, refineries and is diluent for heavy oil. BP and Kinetic Resources, a subsidiary of Provident, as well as Tidal are some of the major purchasers of Alberta NGLs.

Most extraction capacity in Alberta is in place to process gas destined for non-Alberta markets. The Edmonton plant and the Joffre extraction plant are unique as they remove ethane and NGLs from gas consumed in Alberta. For example, for the picture of EEEP, demand for gas is driven by the Edmonton residential and industrial demands. This plant straddles the ATCO pipeline system, which delivers this gas to meet the Edmonton area market demand. The gas is sourced from numerous production areas, as well as TransCanada's inter-Alberta system. As long as the Edmonton market demands gas, this plant will extract ethane and NGLs and the potential to expand the plant exists as the Edmonton market demand grows.

I'd like to discuss our Enhanced Ethane Recovery Project, which will be operational at the end of the month. This project will increase the processing capability at EEEP by 15 million cubic feet a day and will increase ethane production net to AltaGas by about 700 barrels a day. The capital cost of the project works out to be about \$3,000 per barrel and this is estimated to be about 60% of the per barrel cost of other recently announced ethane projects. There is a potential to increase the ethane recovery using a similar process at EGLJV as well.

Our pipeline businesses consist of five natural gas systems and one liquid condensate line. The Suffield gas transportation system provides over 90% of transmission revenues and is backed by an EnCana contract with an annual volume commitment expiring in 2022. The pipelines are located in strategic locations. For example, Suffield moves export volumes to markets east. Porcupine Hills is a key intra-Alberta link from the Shell Waterton Plant to move condensate north for diluent to oilsands and Cold Lake is a gas transmission system near many SAGD plants, Steam-Assisted Gravity Drainage Projects. The transmission lines provide links to other areas of our business, which I'll describe in a minute.

In summary, the E&T business has long-life assets and stable cash flows. Only 7% of the net revenue is exposed to commodity prices and volumes. There are a couple of key risks in the extraction business that we manage through a variety of commercial arrangements. We enter into long-term fee for service arrangements with customers like Conoco to process their gas as well as process volumes transported to eastern markets by our Energy Services segment. We reduce our price exposure to product prices and gas shrinkage costs by providing fee for service as well as cost flow-through arrangements with major ethane and NGL producers. And for the remaining 7% of our production that's subject to gas price risk, we have the ability to re-inject the NGLs if the product becomes uneconomic.

A key part of our everyday business is our ability to create unique opportunities among our business segments and our Cold Lake Transmission System is a great example of that. At Cold Lake, we have seven gas plants and compressor stations processing market specification gas into our Cold Lake Transmission System.

Energy Services purchases production from about 25 producers and moves gas to 10 different markets, including deliveries to AltaGas Utilities, ATCO Gas, the County of Vermillion for further transport to their local markets on their systems. This area has a significant existing and potential heavy oil and SAGD demand for gas, which is used to create steam in companies like Imperial Oil, Shell, CNRL, and Devon are active in the area.

Last Thursday, AltaGas announced plans to expand the Cold Lake System to provide transportation for BlackRock Ventures, the subsidiary of Shell Canada, for natural gas supply and transportation capacity to service BlackRock's Orion SAGD plant. AltaGas will invest approximately \$2.5 million to install compression and construct approximately two and a half miles of eight-inch diameter pipeline from our existing Cold Lake Transmission System to the Orion plant.

Natural gas deliveries of up to 17,000 GJs are expected to commence May 1 of 2007, and the project capitalizes on the value chain benefiting both gas services, transmission and Field Gathering and Processing. Our synergies extend to our operations as well as our commercial arrangements. We currently operate 25 megawatts of peaking power facility that Jim mentioned earlier. We operate in four locations in Southern Alberta, and we operate them from our control room in EEEP in Edmonton. The control room monitors real-time power prices and from the moment we start the peaking plants to full operations is 10 minutes. We are looking forward to future opportunities to centralize some of our transmission operations at EEEP as well.

In summary, we'll continue to work with Energy Services and Field Gathering and Processing to optimize operating income around new and existing businesses as well as conduct expansions to capture new volumes in response to supply market conditions.

I'd like now to discuss our Field Gathering and Processing business. Field Gathering and Processing was the engine of AltaGas' early growth, and I'll be discussing why we're well positioned to achieve future activity and advantages in the future. In our Field Gathering and Processing business, our 74 facilities have a total licensed capacity of just over a Bcf a day, of which approximately 26% is in sour gas processing. We also have more than 6,000 kilometers of gathering lines. We operate 71 of these facilities, which allows us greater flexibility to control operations and increase efficiency and throughput wrought by redeploying facilities to areas in new or high activity. We're able to do so due to the fact that almost 200 of our compressors, for example, are skid-mounted. We actively pursue a strategy to construct or acquire processing facilities and existing in new operating areas that can be or are connected since this complimentary operation allows flexibility and reliability. In 2005 and year to date 2006, our reliability has been 98%.

Producers want to bring their gas to market quickly, economically and be assured that they will have access to processing facilities for existing and new production for as long as they have area operations. AltaGas provides commercial and operational model that allows producers to focus on their exploration and production with assurance that their volumes will flow to markets. Our pricing options include fee escalation where fees increase based on CPI in areas where we have fees designed to cover both operating cost and capital recovery, and capital fees with flow-through operating costs for our new facilities and where operating cost are subject to high variability.

Where AltaGas spends capital, we set up arrangements with producers called area of mutual interest or AMIs, which all production in a defined geographical area will flow to our facilities. In addition, producers agree to pay fees based on minimum volumes whether they're processed or not, take-or-pay. By having the majority of our facilities on skids, we can redeploy capital quickly in response to producer drilling successes.

I'd like to take a minute to discuss the health of the Western Canadian Sedimentary Basin. There's little debate that gas demand will continue to increase but there has been some concern raised over the ability of the basin to continue to deliver. A recent Ziff study suggest that production from the basin will be maintained as declines in conventional gas are

offset by increases in coal bed methane production over the next few years, suggesting that there is at least 660 Tcf of coal bed methane potential. We expect normal declines will generally be offset by continued activity in the basin including increases in coal bed methane and tight gas production.

AltaGas operates in 29 different areas of the Western Canadian Sedimentary Basin. More than three quarters of the raw gas produced in this basin over the last few years has been in areas indicated on the map where we operate. We're well positioned to take advantage of future activity in both CBM and conventional production.

This graph shows AltaGas processed throughput since 2003. Throughput has increased although you can see that there's significant variability within the year. In the second and third quarters, volumes normally declined due to a couple of factors. Some of our plants in the Northeast and Northwest of the province are subject to winter only drilling and after winter breakup, drilling is suspended. The summer months reflect natural well declines until the next winter's drilling season commences. The summer months are also times when most maintenance occurs on wells, gathering and processing systems and downstream pipelines. Production is temporarily reduced or suspended during these periods. Volumes recover in the fourth quarter as normal operations commence, and are maintained and increased through the winter drilling season.

This slide shows the volumes processed per million dollars invested. You can see that in west of four and west of five, our capital efficiency is at its highest reflecting the continued high activity in the area. We expect this trend to continue and increase as CBM develops. West of six in B.C., we currently have low capital efficiency. West of six includes recent acquisitions: Blair Creek, Clear Hills and Clear Prairie. All of these plants are in highly prospective areas with recent high land sale activity and significant drilling potential. So efficiency will improve as producers develop in the area. In addition, these areas have higher fees. The comparatively low capital efficiencies you see in Saskatchewan is offset by significantly higher than average fees. At Shaunavon, for example, where we process solution gas, fees are in excess of \$1.75 an mcf. Since 2003, our fees have increased by 17%. This is due to three main factors. First, we have escalation in contracts. As I mentioned earlier, the majority of our contracts increased in conjunction with changes in CPI, and this represents above 30% of that increase. Increasing flow-through operating costs in the past years account for 40% of the increase, and the remaining 30% is related to capital fees on new projects acquired or expanded in the last four years.

Operating costs have recently been increasing at rates greater than inflation. And AltaGas has been moving towards recovery

of more operating costs in Field Gathering and Processing. We currently recovered over 40% of our total operating cost. All new development capital has flow-through operating cost associated with it. And over the last two years, we've converted about 10% annually from fixed to flow-through operating.

New capital investment, whether it's constructed, acquired or expanded is underpinned with a combination of areas of mutual interest or AMIs and take-or-pay commitments from producers. The AMI provides producers with the security to know that he will be able to access processing capacity within a defined area and provides AltaGas the commitment that that plant will process all future producer volumes. In total, we have G&P agreements that dedicate approximately 14 million acres or 21,500 sections of land that various producers have dedicated to AltaGas facilities. Only one of our 74 facilities have no contracts with AMI provisions. Some of the producers with significant AMIs include ConocoPhillips, CNRL, Trilogy, Penn West and Prime West.

In addition to the AMIs with producers, we also enter in to take-or-pay arrangements, which obligate the producer to pay a minimum fee regardless of the gas volumes processed. The terms of these arrangements are usually three to five years but may be longer. This underpinning helps secure the financial performance of the asset. We currently have in excess of 100 million a day or about 18% of our throughput under take-or-pay contracts. The producers with take-or-pay commitments include Trilogy, Enerplus, and Kereco. In the past 12 months, we have constructed two plants, Clear Prairie and Princess, as well as acquired the Blair Creek and Clear Hills plants immediately upon construction by producers. All of these plants are in areas where we believe there is high development potential, and we have licensed the plant capacity anticipating the growth. For example, current processing capability based on the assets in place at Princess is 15 million a day, but was designed so that we could easily add compression to process up to 20 million a day of licensed capacity when the volumes materialized. Should this additional compression be required, the processing fee will change accordingly. In the case of acquisitions, the capital was paid based on the actual construction cost and the fee adjusted automatically eliminating construction risk to AltaGas.

The recent expansion of Prairie River is a great example of how AltaGas adds value. Last winter, the producers with existing AMI and take-or-pay obligations at Prairie River was successful with their winter drilling program and required additional capacity. The original producer plan was to wait until freeze-up and build additional gathering lines. AltaGas was able to offer the alternative adding skid mounts and field compression to the existing system, as well as moving a skid-mounted refrig and

compression to the plant site. This enabled production to come on stream an estimated six months earlier than originally anticipated. As part of this process, we identified additional third-party volume that would utilize the expansion. This plant has become operational in September and was backstopped by additional take-or-pay and AMI provisions.

On average, we move about six to 10 compression units a year in response to producer requirements. Current lead times on ordering equipment has been as long as four to six months in this year. And we're often able to move, install and commission skid-mounted facilities inside of six weeks. In this photo, the truck on the left is moving the refrig unit on site at Prairie River while the truck on the right holds the compressor.

The Clear Hills plant acquisition is another way AltaGas creates value. This plant was built because producer-owned facilities in the area were unwilling to provide secure access to processing and were unwilling to invest capital to expand their facilities for third parties. The third-party producers needed to have guaranteed access to processing capacity, but they preferred to commit their funds to drilling. AltaGas provided a solution. We agreed to backstop the construction of the sour gas facility by acquiring it when it was commissioned and then contracted additional area producers and guaranteed processing capacity to them. Currently, our utilization of this facility is 85%.

We're also dealing with the risk associated with gathering and processing. With respect to possible declining volumes in the basin, we're well positioned to move equipment to where the development is. With our 29 operating areas, we'll continue to redeploy those assets as production profiles evolve. Part of that Prairie River expansion did include moving up compressor from our Thornberry unit, for example. And we will continue to match producer development and assets. With respect to increasing cost, we plan on flowing through 50% of our operating cost by the end of next year but we're also undertaking to reduce cost as well. For example, we expect to reduce our lube oil cost by at least 5% to 10% next year through refinements in our plant maintenance and through bulk purchases.

Skid-mounted facilities allow us to reduce producers' cycle time and install low cost right-sized facilities. We'll continue to look to build, buy and move facilities depending on opportunities. Producers won't need assured access, we need to right-size the operations and we need to, wherever possible, interconnect facilities to increase reliability. With over 240 total customers, which include ConocoPhillips, Exxon Mobile and CNRL, we expect to continue to capture opportunities in the Western Canadian Sedimentary Basin. AltaGas' field operational expertise has allowed us to maintain cost while maintaining high reliability and safety compliance. In summary, we continue to see opportunities for sustainable growth as

producers focus on exploration and production while we focus on processing. Our skid-mounted facilities and continued strong demand in the basin will provide us opportunities to expand, construct and consolidate facilities' efficiency. Thanks for your time and I'll field any questions if there are any?

Winfried Fruehauf: My first question is on slide four.

Marshal Thompson: Okay.

Winfried Fruehauf: Can you please explain how you can have inlet gas of 393,000 Gigajoules outlet of the same amount, but you haven't shown us where the fuel comes from; the 500 Gigajoules?

Marshal Thompson: You'll notice that we show shrinkage in the top, that is the balance between the NGL-GJs produced at the bottom and the ethane produced at the bottom as well as the fuel used each year. So if you total that fuel usage with the ethane and the NGL, you'll equal the shrinkage makeup. Really in terms of practical operations, the shrinkage makeup is commingled with the inlet gas. So in total, you've got--if I do my math right--456,000 GJs coming in to the plants, 393 GJs leaving the plant. I think the important thing to note with demand plays--it's all based on demand. So it really starts at the market demand is 393, and the math works backwards.

Winfried Fruehauf: And where about is (inaudible) lost and unaccounted for gas?

Marshal Thompson: Inside an extraction facility, there's very little lost and unaccounted for and if it's anywhere, it's in the rounding of the fuel.

Winfried Fruehauf: Other question is on the new ethane policy of the government of Alberta. Actually, I'm not sure if it's really new. But what are the implications of the oil that we leave that's supposed to stimulate ethane extraction in Alberta for AltaGas?

Marshal Thompson: Well, we participated in that with a number of other players in the industry. It's designed to encourage incremental ethane to the extent there is a shortfall of ethane demand. I think there are a wide range of views on whether that ethane demand shortfall is real or not. Personally, I think it's pretty much in balance. And then there are other opportunities to turn on field plants that are currently not operating. So, I think the ethane is available but what it was designed to do is to encourage increased ethane and hopefully increased ethylene usage in Alberta.

Winfried Fruehauf: Well, I had wondered about the implications of this ethane policy for AltaGas in terms of perhaps brownfield expansion or even greenfield plant construction--ethane extraction.

Marshal Thompson: Yes. I think if anything, it would be positive. I mean, anything that creates some incentive to create more ethane genuinely would be positive and we'll look to participate in it. As I've said, we've expanded the Edmonton plant without considering the economics associated with the policy, but we have a similar opportunity at EGLJV, the Empress joint venture that we own as well. So it is possible to make those low-cost investments.

Winfried Fruehauf: And one more, if I may. What happens to sulfur extraction that gives our gas plants; how are you being compensated for it, are you responsible for marketing--perhaps you could explain that?

Marshal Thompson: Sure. We don't market any sulfur ourselves. Taking Princess for an example, that is a zero emissions plant. We just commissioned an acid gas facility. So, we are now injecting the acid gas and the CO2 back into the formation.

Fai Lee: With the move towards more flow-through, your plan to increase flow-through of your operating cost to your customers, what is the expected impact on margins going forward?

Marshal Thompson: I'd say generally, we'd expect margins to increase. It really takes the variability out of operating costs that we incur in the future. I think the advantage, too, is it better aligns us with the producer. So, we're operating on the same line as them and we treat them the same way. Anything else? Okay, thank you. So, we'll just take a 15-minute break. Thanks.

Richard Alexander: Thank you everyone. We'll get started on the second half of the presentations now, if we could. My name is Rick Alexander and I'm the Chief Financial Officer for AltaGas. And I'd like to now give you an overview of some of AltaGas' growth opportunities.

AltaGas has an experienced and diverse business development team whose objective is to pursue expansion, green field development and acquisition opportunities in all of our business segments. We look at opportunities in our existing and new business lines that integrate with our current businesses.

With AltaGas' diverse asset base, we are well positioned to capitalize on the drilling activity and the future demand for power. Today, we have over \$100 million of capital available for investment without having to go to the equity markets. We will also look at major transactions above this level, and as you will see in our financial strategy, have adequate access to debt and equity markets to execute larger type transactions. We target assets that support our goal of extracting value from the interconnection and interdependency of our business segments. We continue to use financial discipline in our investments. So, we have not been capital constrained despite our large deal flow. We have a strong track record of efficient use of capital.

AltaGas is creating unit holder value, not just growth. At AltaGas, our bonuses are based on earnings per unit and return on equity. Investments must be at our business strategy and risk profile. Investments must be underpinned with a strong contractual commitment and have manageable commodity exposure. AltaGas benefits from the diversity of our business and continues to see strong deal flow.

Our historical growth shows the balance that we strive to maintain between our business segments and the consistency in our business strategy over time. Although the growth is lumpy, you can see that the strategy is to grow all our business segments. Some historical investments of note: In 2001, we made our first investment in power with the 50% interest in the Sundance B PPA. Since then, we acquired the Southern Alberta gas peaking assets; We also acquired a three-year Genesee strip contract. However, there was no capital cost and as such, it does not show up on this chart. In 2004 and 2005, Energy Services acquired PremStar and ECNG and the iQ2 energy procurement and management businesses.

During the entire period, we have continued to pursue organic growth and acquisition opportunities that have presented themselves in the FG&P business segment. The extraction business shows the 2004 acquisition of EEEP. We continue to see excellent growth opportunities in British Columbia and Alberta West of five and six. Record drilling is also occurring in West of four and we see growth opportunities there, driven by conventional and coal bed methane drilling successes. We see opportunities to spend more than \$40 million on organic growth in the Field Gathering and Processing segment in 2007. There also continues to be opportunity to further consolidate the midstream business. With 3% of the basin throughput, AltaGas has lots of room for continued growth.

We recently commissioned a study to evaluate an area southwest of Edmonton, running from the Pembina field in the northwest, to the Stettler area in the southeast. We have nine facilities in this area with a total capacity of 126 million cubic feet per day. In 2005, we processed a 106 million cubic feet per day or 9% of the produced gas. The study forecast a 16% growth in production in this area driven by coal bed methane. The study shows from 2005 to 2010, that coal bed methane will grow from 17% to 47%, and sweet gas decreases from 65% to 44%. The sour gas falls from 18% to 9%. So as you can see, coal bed methane has the potential to change the landscape of the basin.

We believe that coal bed methane production will increase and we are well positioned to capitalize on this opportunity to provide significant potential upside to throughput at our facilities. For those of you who are not familiar with coal bed methane, it is a natural gas found in coal seams. It acts almost

like dry gas and therefore requires dehydration and compression, both core strengths of AltaGas. It also tends to have a slower decline profile than other more conventional reserves, which provides ideal long-term cashflows for a trust. These reserves tend to be found in Central Alberta, in areas where we have substantial infrastructure already. The areas you see highlighted are the Mannville and Horseshoe Canyon areas. The Horseshoe Canyon area is the most developed. According to Ziff Energy, there are 660 Tcf of coal bed methane potential in Western Canada and we think this is a conservative estimate. Success rate is about 9%, which is very successful. And we expect to see producers bringing on about 60 million cubic feet per day over the next year.

In extraction, we see the opportunity to increase ownership interest and to expand the plants to increase liquids recovery. Our preference is for market pull extraction plant capacity, which Marshal talked about earlier, that will ensure continued demand regardless of potential leaning of the gas competition. AltaGas has a buyer advantage, as it is not a competitor in the downstream liquids marketing business. In transmission, we continue to pursue new markets and expand our footprint primarily in smaller oil sands opportunities. The recently announced Orion Project is an example of this. There is potential to capture synergies with our existing gathering and processing assets and Energy Services segment.

AltaGas has participated in the Ontario, Alberta and British Columbia calls for power, and plans to submit several projects in the upcoming Manitoba RFP. We continue to focus on both fossil fuels and renewables. Having a diverse business development group, with five originators, together with our developer relationship, means that we have substantial deal flow. Our GreenWing Energy Development Partnership brings forward acquisition and development opportunities across Canada and the United States for both fossil fuel and renewable power generation. AltaGas has the option to participate fully, to syndicate deals, or to pass. We will target areas where we expect to see strong demand for power generation and where there is an opportunity to lock-in long-term off-take contracts with credit worthy customers. Areas include Ontario, Western Canada, and the Northern United States.

Our relationships with partners will provide a competitive advantage through increased deal flow. We have entered into a five-year partnership with GreenWing Energy to source power generation opportunities. The partnership is expected to be ready to bid three separate projects totaling 300 megawatts into the Manitoba RFP. As Jim discussed earlier, the Bear Mountain Wind Farm is a 120-megawatt wind project located in the Peace region of Northeast B.C. where wind studies show 85% of the wind resource in B.C. AltaGas partnered with Aeolis

Wind Power Corporation in Bear Mountain and we are seeking further partners.

The following projects show AltaGas' strategy in action. There has been a balance of expansion, green field development and acquisition growth activity in each of the business segments. A few of the highlights are at Prairie River, where we spent \$9 million of capital to install refrigeration and compression to increase volume by 10 million cubic feet per day. The Sundance B upgrade, as discussed earlier, where no capital is required but we expect to receive a gross overriding royalty of 12%, and increased capacity of close to three megawatts, and at Princess, where we spent \$14 million for 20 million cubic feet per day of sour gas processing in late 2005.

This conceptual model shows the value that can be realized from the integration of the AltaGas business segments. A co-generation plant built next to one of our field gathering and processing plants will produce electricity that can be sold into the grid, supply electricity to the field gathering and processing plant and to our Energy Services retail business. The co-gen will burn gas produced by the plant and generate heat to be used in the field gathering and processing plant operations. Energy Services will market the liquids and gas production from the gathering and processing plant, providing the marketing service to our customers.

This is one illustration of the types of integration that are possible across our businesses. As you saw in Marshal's and Jim's presentations, our businesses operate within this model and we are able to deliver time-sensitive essential services to our customers who produce and consume energy, which result in strong financial performance and the return to our investors. Our growth strategy is to continue to do so. We have the opportunities, knowledge, expertise and financial strength to grow.

You're looking at a map showing the locations of some of the potential projects we are currently working on. In Manitoba and North Dakota and Wyoming, where we're working with GreenWing. The Bear Mountain Wind Farm in B.C. with Aeolis Wind Power. And we're looking at storage opportunities in the east, additional G&P facility expansions, acquisitions, or developments like Blair Creek, Princess, Prairie River. The EEEP expansion and the Cold Lake Transmission expansion, we talked about. AltaGas has the opportunity to invest approximately \$100 million--the opportunity to invest in approximately 1,000 megawatts of wind power over the next five years. As we talked about earlier today, we don't believe that all the projects will be successful, there will be less than 100% success rate in the RFPs and in some project economics will not meet investment criteria. So, 25% percent of projects is an estimate of what might go ahead and if more go ahead

then we will look to additional strategic partners to keep a diversified portfolio. This could mean between \$250 and \$500 million of capital over the next five years. As projects get bid into auctions and contracts are signed, we'll tell you more about them. We expect to see a continuation of this type of growth activity in all our business segments.

I'd like to now give you a financial overview of AltaGas. This slide shows our strong track record of delivering value to our investors. As you can see, EBITDA grew 57% from 2001 to 2005. Net income climbed 234% and funds generated from operations increased by 81%. So far, our results continued to increase over last year's reported levels. Net income compound average growth rate was 35% for the period shown. Funds from operation compound at annual growth rate was 16% for the period listed. Our year-to-date numbers are strong. With one more quarter to go, we are almost where we were for the entire year in 2005. And last year was a record year. Third quarter earnings were \$28.8 million, a 67% increase over Q3 '05. Year-to-date earnings of 87.2 million, a 36% increase over the first nine months of last year. The strong third quarter was driven by a number of things. Strong spot-power prices and effective hedge prices, lower transmission cost, higher frac spreads, which were about \$25 in the third quarter versus about \$11 the same period last year. Lower interest expense was due to both lower balances and lower interest rates. I believe our interest rate was about 90 basis points lower than for the first nine months last year and a 6.6 million non-cash future income tax benefit as a result of the reduction in federal and Alberta corporate income tax rates. These increases were partially offset by higher administrative and compensation expenses to support growth, lower contribution due to the spinout of the Natural Gas Distribution segment and a \$7.9 million gain related to the investment in Taylor in Q1 last year.

Our primary objective is to grow earnings with no or minimal dilution. To that end, earnings for Q3 '06 were \$0.52 per unit, a 63% increase from Q3 '05. For nine months, earnings of \$1.58 per unit or a 33% increase year-to-date from 2005. Adjusting both items for one time--for both years for one-time items, our year-to-date net income rose by 43% compared to 2005. This year, we have had an average of 1.4 million additional units due primarily to the DRIP Program. Weighted average units outstanding of 55.2 million in 2006 compares to 53.8 million in 2005. Q3 EBITDA of 45.1 million was a 28% increase over Q3 '05 and nine months EBITDA was \$128.6 million, an 11% increase over last year. Funds from operation is the most common measure of ability to pay distributions. For Q3, AltaGas generated \$42.9 million, a 38% increase over Q3 '05. For nine months, funds from operations were \$119.8 million, a 29% increase on a year-to-date basis. With third quarter distributions declared of 50.5 cents per unit, we had a

payout ratio of 65%. Year-to-date, our payout ratio is approximately 68%, down from last year of 79%.

AltaGas' return on average equity continues to grow year-over-year. This clearly illustrates our focus and execution of value creation for the unit holder. At AltaGas we believe in maintaining strong business fundamentals. At September 30, 2006 we had a debt-to-total capitalization of 34%. We target 40% to 45%. We strive for sustainable growth, growing distributions and growth projects must be cash flow and earnings accretive. In addition, our conservative payout ratio provides additional capital for reinvestment to create unit holder value.

This slide illustrates our growing and disciplined distribution level. Both metrics are presented using trailing 12-month data. As you can see, the funds from operations continue to grow at a favorable pace. Our target payout ratio is between 70% and 80%. In addition, we have a payout ratio target to grow earnings faster than distributions. We believe that we have a cushion already in place, which will provide some protection against the potential tax announced for 2011.

Our financing strategy is aligned with our growth strategy. We focus on these five key areas of success. One, minimize our cost of capital. Even after the tax developments we feel our cost of capital is competitively low. This is important to maximize value from our projects and business. To maintain optimal financial risk level, the amount of leverage is optimized to balance off maximizing returns to equity holders while not adding excess financial risk. Three, ensuring liquidity and solvency of the firm. By ensuring liquidity and solvency, we will continue to run the business effectively and efficiently and be positioned to grow. Four, provide a platform to effectively fund new growth initiatives by ensuring flexibility and raising capital from multiple sources and markets. Because our capital structure is strong, we believe that we have a solid access to multiple capital markets. For example, banks, public debt, private debt, equity, etcetera. And disciplined project evaluation and hurdle rates. Our project evaluation is done by using a specific hurdle rate designed to reflect the riskiness of the project and add value for the unit holder.

Over the last seven years, average all in cost of debt differences is about 2% between investment grade and non-investment grade debt. But more importantly, at times below investment grade firms have no or uneconomic access to capital markets for financing. Therefore we target an investment grade rating between BBB- and BBB+. We believe our distribution payout ratio supports AltaGas's market valuation and allows some funding for growth opportunities. Given AltaGas's current business risk profile, the optimum financial risk is debt-to-total cap of 40% to 45%. And given

the long-term interest rate environment, we believe the optimum amount of floating-rate debt is 25% to 30%.

As I said, management at AltaGas has a conservative approach to the financial management of the trust, with a focus on maintaining our strong balance sheet and investment grade credit ratings. We are proud of our stability rating and think that it indicates the strength and sustainability of our distributions; our effective risk management strategies in diverse businesses. However, due to the recent announcement of tax changes for trust, DBRS has put us under review, along with all other income trusts. We are ultimately confident that there will be no change to the AltaGas rating. Our credit metrics and business fundamentals continue to be strong.

Finally, we can fund up to \$100 million in growth projects without issuing any new equity. AltaGas has a strong liquidity position and capital market access to fund the business and growth. As of Q3 2006, we had over \$200 million in available credit facilities. We believe that strong liquidity is necessary to support a smoothly operated business. For smaller projects that are up to a \$100 million in aggregate, we would not seek to issue any new equity. The most cost effective method to finance organic growth is by: one, using non-distributed cash flow that's quickly re-injected in high-return projects; and two, available bank financing from our credit facilities. For the larger projects and acquisitions, we would plan to access the capital markets for funds.

We have a \$500 million Universal Shelf Prospectus, which was issued in April of 2005, for 25 months, under which we issued \$100 million of medium term notes leaving \$400 million. We would draw on these resources for high-return projects.

One of our financing objectives is to extend AltaGas's average debt maturity to secure our capital structure and reduce long-term interest rate exposure. This slide illustrates our debt portfolio maturity. The MTN is due in 2010, and the smaller bars represent our fixed rates swaps that are currently in place. The majority of our debt portfolio is at fixed rates. We want to work towards matching our debt profile and our asset profile. Although terming out some of our bank debt will slightly increase our cost of borrowing, it should further reduce AltaGas' financial risk.

AltaGas has always operated with the discipline of a corporation, by focusing on net income, return on equity and creation of long-term unit holder value. Unfortunately, the effect of the distribution tax is moved to the trust level. In addition to wealth destruction, it particularly hurts the cash yield for exempt and non-resident unit holders. The government indicates that a Canadian taxable unit holder is

neutral in its after tax cash yield, but it depends on provincial tax rates and individual circumstances.

Implications of distribution tax on income component of distributions, has significant implications for AltaGas. Our income component of distribution in 2004 was 76% and 78% in 2005. Results for the year 2011 and beyond will be dependent upon future levels of profitability, and capital expenditures, as well as the amount of inter-company interest. Tax assets such as capital cost allowance arising from capital expenditures will have more value to AltaGas than they did before.

This slide shows another perspective on our financial performance over the last 5 years. Our total return was almost 700% over the period. And in 2005, our total return was 31%.

At AltaGas our goal is to continue to deliver sustainable earnings and distribution to unit holders, supported by sound economics and traditional financial metrics. We have a demonstrated track record of growth and value creation, and a solid business today were significant opportunities to continue to build and grow. We are in business for the long haul, and our strategy is to build today for the future.

At AltaGas we believe that good governance improves performance and benefits all unit holders. And we believe that we have a strong independent oversight. We have a strong board of directors with extensive experience, all but one of whom is independent and unrelated. Since David, the only unrelated director, is Chairman of the board, we also have a lead director in Myron Kanik. The board is currently in the process of searching for a replacement for John Breen, who recently left the board to pursue other professional opportunities that do not allow him to stand on public boards. AltaGas will continue to have a strong independent oversight.

Finally, included in the handouts today, and on our website is the list of the AltaGas core values. Our number one core value is safety and environment. As a result of living these values, AltaGas has received numerous recognitions from governments, community groups, and industry. Listed here are only a few of a long list of recognitions that demonstrate our commitment to the community we work and live in. Thank you.

I'll now open it up to questions. And I guess before we start the questions, I just want to add to Jim's answer early as to why, I guess, I personally think Bear Mountain will be successful. Some of the points that perhaps didn't come out in the earlier discussion, on the wind data, we have 3 years of wind data at the site. But we also have correlation data, and this is something that's more prevalent in the new projects versus the original projects that didn't have as much success. And what we do is we take the 3 years data we have, and we

look to wind data in other sites that are nearby, that have a longer history of data. And in fact, we have done a correlation to wind data that's 25 years in length with an extremely high correlation factor. And so what that does, it gives you additional assurance that your wind has a long-term record.

The other point I'd like to make is that with Enercon. One of the key reasons we chose Enercon, besides being one of the leaders in building European wind turbines, is they have a gearless turbine, which historically has shown it is significantly--require significantly less maintenance. And in addition, Enercon has agreed to provide a long term fixed price maintenance contract so that we have significantly mitigated the risk and they are significantly committed to reliability. That low project is risk-free that's why our strategy is to have a geographically and project diversified portfolio. So it is possible that despite all the hard work we've done, that we may have been over optimistic in the wind. But our strategy is to have wind turbines, wind farms in several geographic locations and we believe that that diversification will lead to a long run strategy that's successful. So with that I'll open it up to any other questions. Linda?

Linda Ezergailis: Thanks. Just wondering--I mean its still early days with all this trust tax announcement being so recent and I would imagine that some of the financial slides are kind of subject to change in terms of leverage and everything. About 25% assumed success rate on your power--wind power RFPs, is that accounting for your new hurdle rates or was that a number that you converged upon prior to this trust tax announcement?

Richard Alexander: No, I believe it is applicable to the new hurdle rate. Obviously, these are long-term projects and we'll have to look at them on an after tax basis under the new regime. But we have a pretty rigorous hurdle rate process, analytical process, and we're still confident that once we develop out these projects that we can have success in at least 25% of these projects. And if it's larger, we'll look to use strategic partners to keep our portfolio diversified and our risk at a manageable level.

Linda Ezergailis: And how do you see the competitive landscape changing in terms of both acquisitions and green field, brown field initiatives that you're taking on after this trust tax announcement? Do you expect it to change at all or?

Richard Alexander: Well I think there will all be a change in the acquisition landscape. Everyone's cost of capital will undergo a change. But at AltaGas, we've always focused on income and return on equity. We have approached the financial analysis as if we were a corporation with great stringent protocols. And I don't see that changing. So for us, I don't see a change in the way we look at new projects or acquisitions. Obviously there's some uncertainty and until the new regulations come out or

legislation, it's difficult to be certain but we're confident we still have a competitive cost of capital.

Linda Ezergailis: Have you been approached by potential partners on the pension side or private equity that are interested since this announcement; in the field they might be able to give you some advantage to cost of capital?

Richard Alexander: I wouldn't comment on that.

Linda Ezergailis: Okay.

Richard Alexander: Thank you.

Unknown: Could you talk about the operating margins in your four business areas?

Richard Alexander: Well the margins are all different, that's why we have a different hurdle rate for every segment and every project within every segment. So, I don't want to give out what our hurdle rates are for obvious competitive reasons but we basically go through every project to apply a process to determine what we think is the appropriate hurdle rate for that specific project. And then we do rigorous analysis and sensitivities to give ourselves the confidence that--

Unknown: I'm sorry. I wasn't asking for your hurdle rates, I was just asking what are your achieved operating margins in the four businesses, generally speaking.

Richard Alexander: I don't--

Unknown: Do you not publish that?

Richard Alexander: We do. It is in our quarterly report that we just released but I don't have those numbers off the top of my head, sorry. It would be in your binder.

Dominique Barker: Can you just talk about particularly with the Field Gathering and Processing segment and I suppose to a certain degree extraction, at what price does the management team--but national gas prices and management team start to get a bit uncomfortable? Can you just talk about the risk and how far natural gas price has to go for it to impact your business? I'm not suggesting it goes there, but I just want to understand, and I think a lot of people would want to understand the potential risk if there is any.

Richard Alexander: Unfortunately there isn't a specific price, because the price can fall as it has, and go back up. It really is a factor of not just how far it falls, but how long it stays low. It has to stay low and long enough that it significantly impacts the drilling activity in the basin. To date, we have seen a slight decrease in drilling activity. We tied in 75 versus 90 wells in this past quarter,

compared to the previous year. We expect that to pick up as we go into the winter. So in addition, we have the factor in producers' expectations of price, and historically producers have tended to be somewhat optimistic. So it's difficult to put a number on it. In addition, we do a lot of things to mitigate that risk for example as Marshal talked about earlier, moving to flow through cost, with over 40% of our contracts flow through cost now, and an objective of increasing that by about 10% a year. We will significantly mitigate the impact of lower throughput risk as we go forward.

Dominique Barker: And just going back to the Sundance B, AltaGas pays any cost from change in law. Would that include something like carbon dioxide rules?

Richard Alexander: Yes.

Dominique Barker: Okay. And then also the hundred million investment that you referred to, what time period is that? Because obviously, you would start to generate internally generated cash flows? So is that sort of for the next 12 months?

Richard Alexander: That would be today, and we have between our existing debt capacities to stay within our target and credit ratios, and then the cash we're generating over the next 12 months. We would feel confident looking up to a hundred million dollars in investment opportunities today.

Dominique Barker: Okay, thanks.

Fai Lee: Rick, compared to sweet gas margins, cold bed methane margins--what are your expectations if we are moving to more cold bed methane, how do they compare on a relative basis approximately?

Richard Alexander: Well, Marshal's probably better equipped for this, but the margins are similar I believe, but we have--because they're a longer life asset, they have better economics. Now one of the keys is to get back the gas price, is that certain gas prices; the drilling with the success rate the industry has seen, isn't successful for coal bed methane, and we estimate that price to be about \$6.00, \$5.00 to \$6.00 an mcf.

Fai Lee: Right, I guess I'm wondering in terms of the margins, it's drier gas, so you would not receive a lower fee for that?

Marshal Thompson: Actually coal bed methane is really quite capital intensive. Because it's so low pressure when it comes out of the ground, you need either big, big pipe or lots of compression and so there's a quite a competitive advantage I think, if you have structure in place, which we have working with coal bed methane areas. But in fact, in terms of the processing cost fall in, they can be quite high depending on shrinkage at compression versus pipe.

Fai Lee: So the compression offsets the processing element of the fee?

Marshal Thompson: Yes, and I think the other part that you have to factor in is the shrinkage that's associated with that compression. If you've got, for example, 5% shrinkage at \$6.00 gas, that's implicit to the producer of \$0.30 fee.

Fai Lee: Okay, thanks.

Winfried Fruehauf: A couple of questions, regarding Horseshoe Canyon, if we take the more prospective known portions of that canyon, what is it of the range of on stream cost of gas between sort of the lowest and the highest?

Richard Alexander: Marshal you want to--

Marshal Thompson: Boy, I would be thinking it's in the range of the \$4.50 to \$7.00 range.

Winfried Fruehauf: Well that's considerably higher than the old PanCanadian number of stated price of \$2.20 per million BTU.

Richard Alexander: Is it through high increases in the cost, capital cost, and operating cost. So, I mean that's just my off the top guess.

Winfried Fruehauf: With the respect to the implications of what Mr. Flaherty has done, it's too early to sort of comment, but I have few questions. First of all, do you see an improvement in acquisition opportunities; companies that are in the same or similar businesses as you as a result of what he has done?

Richard Alexander: It's difficult to say, it depends on how everyone's cost of capital falls out after the market settles down, which I don't think we've concluded that it has yet. But our expectation is we'll continue to have an advantage in cost of capital, but until we see the full effect of legislation and the market's understanding of that legislation, it's difficult to say.

Winfried Fruehauf: Based on what you know now, do you envisage ever returning or reconverting to a corporation or do you intend to stay as a trust after 2011?

Richard Alexander: It's too early to say and that's not really my decision. That's the board decision and potentially unit holder decision, so again until we see the legislation and the total impact it has on the organization, it's hard for us to know that. We have started looking at that analysis, but we couldn't make any conclusions at this point.

Winfried Fruehauf: I appreciate that's the board decision, but same comment applies when you might be asked about the level of distribution, so distribution policy or so, but what would you recommend as a CFO of the corporation, returning to a corporate structure, or staying as you are?

Richard Alexander: It's too early for me to make that recommendation, until I see the legislation and know the full market impact.

Winfried Fruehauf: Based on what we know now--

Richard Alexander: I won't make a recommendation to you today.

Winfried Fruehauf: No, but I'm not going to press you for it. Based on what we know today, has the business climate, the business prospects, and the financial opportunities and implications been improving or deteriorating since that announcement.

Richard Alexander: Since that announcement the climate in the market place has deteriorated, no doubt about it. There are extensive uncertainties in the market. We still have the opportunity to do small transactions, acquisitions, but because some of the announcement is unclear in terms of its impact, whereby someone might inadvertently do what the new announcement was and acted to avoid doing, it has created an uncertainty about it and large transaction opportunities in the market place. There's also an unsettled equity market. And so it makes it more difficult to determine at what price you can go to the equity market and for what size. So, those things have all created uncertainty and for those reasons we need to see the legislation sooner rather than later.

Winfried Fruehauf: But you were saying that as long as you spent no more than a hundred million dollars, you don't have to go to the equity market, right?

Richard Alexander: And we still have the ability to do that and we continue to look at projects.

Winfried Fruehauf: But given that uncertainty you referred to, does it mean that the hundred million dollars is going to be remain in the refrigerator for some more time?

Richard Alexander: No it doesn't, because we will just factor in a full after tax analysis on anything we look at starting in 2011 just to be cautious.

Winfried Fruehauf: Okay. Thanks.

Unknown: In regards to the tax pools, which I think were more than six hundred million, so what does that mean in terms of extending the limitation of taxation beyond the four year holiday, how many years would that represent?

Richard Alexander: It's a very complex discussion and analysis and not one I want to get into today, and again, until we see the actual legislation, we don't know how it will impact AltaGas directly. But every trust is structured in a slightly different way, has its own unique idiosyncrasies, and so you have to look at each trust in isolation when it comes to their pools and the impact.

Unknown: I might have missed it, but in the first slide under growth strategy, when it says potential for major acquisition, was that just in reference to the fact that you've got a hundred million dollars that you could--

Richard Alexander: Yes. That was just a reference to, I guess what you could call "dry powder" that we have.

Unknown: So it wasn't in reference to any specific area of the four--

Richard Alexander: No. It would represent a hundred million dollars that could be used in any one of the business segments, all in one segment or in different segments.

Unknown: Given the prospects that you're seeing right now and as you say, things change. Should we expect AltaGas to increasingly be a power company? Is that, in terms of looking at the mix between these four businesses?

Richard Alexander: You should expect that AltaGas will continue to have a significant Power segment. Our strategy is to grow all of our segments. We would like to keep a balanced growth as we move forward. But it's obviously very difficult to plan for when growth opportunities come along in any one segment. And that's why they tend to be lumpy. You might do something significant at one segment and you have to wait a year or two or three years before you can get a balancing opportunity in another segment. But the plan is to have continued growth through all the segments and have a balanced, diversified portfolio.

Unknown: (Inaudible).

Richard Alexander: It appears that way now but we look all the time at FG&P extraction, transmission, Energy Services opportunities. It's just that's what's openly in front of all of us today but it's not a reflection of where we see the strategy going long-term.

Winfried Fruehauf: At the conference call following the conversion into an income trust, David told us that the long-term payout policy of all the gas income trusts is 100% of net income. Where does that stand? Has it disappeared? Does this still apply?

Richard Alexander: Right now, I think, the last quarter payout of net income was 97%. Going forward, we will continue to look at, as long as we're a trust, we will continue to look at the same payout policies that we stated today, 70% to 80% of funds from operation and to try to pay out close to 100% of earnings.

Unknown: Coming back to that 600 million dollars of tax pools, this is a question you will be able to answer. Assuming there were no changes in the proposed taxation of income trust, are those tax pools growing year to year? Or do you use up some of them and draw them down? Yeah, I'll stop there.

Richard Alexander: They grow when we do acquisitions or growth. And they do get drawn down in part in order to shelter part of the income that's used for distributions. And that's about as far as I might be willing to go.

Unknown: So, if the proposed tax rules hadn't come in, do you have a view on when that 600 million dollars might have been used up, if you remained a non-taxable income trust?

Richard Alexander: I don't know that. I don't know that number of years.

Winfried Fruehauf: Is the nature of the 600 million dollars such that a third party hypothetically acquiring AltaGas Income Trust could utilize? Or is it only AltaGas Income Trust that can utilize it?

Richard Alexander: I can't think of any reason why a third party couldn't utilize those pools. Okay so, with that, I'll end the question session for now and I'm pleased to introduce David Cornhill to come up and give the closing remarks. Thank you.

David Cornhill: Thank you. I've got a couple, Rick wasn't part of the trust but the estimate was done at conversion. But we are looking at ten plus years to pool ability in tax-free from a trust perspective. It's a lot of pools and all our new pools are in a tax efficient partnership. So, we have seen some growth there. We quickly checked our disclosure for the answer on operating margin to net revenue. Hopefully, I'm right. I think these are all third quarter. Field Gathering and Processing is 23%. Extraction and Transmission, 53, Power, 92 and Energy Services 26% of net revenue. Those are all disclosed in the MD&A and comparison there.

I am glad to come up late because most of the questions are answered now. I hope you found this presentation helpful, and I think you can see that the business is strong, and we have many opportunities, and we do seek growth. As I said in the conference call, the 2006 earnings will be at record level, and we're setting ourselves up for a strong performance in 2007, and we do see building opportunity.

I think there are opportunities with the new tax legislation change, always creates opportunities for people who want to work hard and dig out those opportunities, and we're clearly looking. Some of the uncertainty around the regulations does prevent us at this point. We're certain to realize those, but we think--people ask me why I was so happy after the trust announcement. I lost, personally, a lot of money that didn't make me very happy, but clearly change like this does create opportunities, and I think it also justified our strategy focusing on earnings and return on equity, and how we structured our balance sheet. We didn't do acquisitions with no tax pools. We built on fundamentals for long-term growth. We do have the energy to grow. We're looking for good growth and going

forward, and I will be happy to answer any questions or try to or I'll be happy to also host a reception over at the mezzanine just across here at the lobby. Win?

Winfried Fruehauf: AltaGas Income Trust has an investment in a little company called AltaGas Utilities, and I'm just wondering how you look at this business? Is it a strategic business? Is it a core business? What do you expect of this business to generate in the next few years?

David Cornhill: We expect growth. At this point, we're holding the investment, and we haven't re-evaluated the options with the new tax legislation. We think that there's significant growth, and I think, in the press release of Utility Group, they are talking about well over 10% growth in rate base next year on their business, and very active growth and good earnings growth. So we're quite pleased with it, and we're supportive of that company--supportive of the company's growth strategy.

Well, if there's no other questions, this has been one of the most enjoyable presentations I've done for AltaGas and I hope you enjoyed meeting the senior management team as well as our other executives, and thank you for the young guys from Ontario to be here as well, and we are hoping that you can join us for a few moments at our reception, and get to talk to a number of our executives and hope I get a chance to talk to you as well. Thank you.