2016 FIRST QUARTER EARNINGS CALL

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PRESENTATION

Operator

Good Morning ladies and gentlemen. Welcome to the AltaGas Limited Q1 2016 conference call. I would like to turn the meeting over to Mr. Jess Nieukerk, Director of Finance and Communications. Please go ahead.

Jess Nieukerk - AltaGas Ltd. *- Director of Finance and Communications*

Thank you. Good morning, everyone. Welcome to AltaGas's first quarter 2016 conference call. Speaking today are David Harris, President and Chief Executive Officer, and Tim Watson, Executive Vice President and Chief Financial Officer. After some formal comments this morning, we will have a question-and-answer session.

Before we begin, I would like to remind you that certain information presented today may include forward-looking statements. Such statements reflect the Corporation's current expectations, estimates, projections and assumptions. These forward-looking statements are not guarantees of future performance and they are subject to certain risks, which could cause actual performance and financial results to vary materially from those contemplated in the forward-looking statements. For additional information on these risks, please take a look at our annual information form under the heading Risk Factors. I'll now turn the call over to David Harris.

David Harris - *AltaGas Ltd – President & CEO*

Thank you, Jess. Good morning, everyone. Before I get started with my formal remarks, I want to thank both David Cornhill and the Board of Directors for giving me this opportunity. David has built a legacy in AltaGas and I intend to build on his legacy. As Chairman of the Board and Founder of AltaGas, I know David is not far away, and I am truly fortunate that I can continue to work closely with him.

AltaGas' success has been driven by a business model of low risk, long life, clean-energy infrastructure assets in midstream, power and utilities. My priority is to maintain this business model and a strong focus on financial discipline in this economic environment. We will continue to focus on our competitive advantage, including being a top-tier operator, and our strong construction expertise. We will look to streamline G&A cost across the organization and we will remain nimble and prudent in how we execute on our growth strategy. The AltaGas team has the skills to deliver customer value and shareholder value.

Normalized EBITDA for the first quarter of 2016 was $178 million, consistent with the first quarter of 2015. Normalized FFO was $132 million, compared to $140 million in the first quarter of 2015. On a full-year basis, these results keep us on track to deliver on our guidance of approximately 20% growth in normalized EBITDA and up to approximately 15% growth in normalized funds from operations.

Results are down slightly quarter over quarter, as we still had the benefit last year of strong hedges in place both for frac spread and Alberta Power. As such, realized pricing for both was down in first quarter 2016, compared to the same period in 2015. For 2016, however, only about 1% of our forecast is based on commodity prices, so this does not impact our guidance. Looking at each of our business segments. In Power, for first quarter 2016 we achieved $43 million in normalized EBITDA, a 34% increase over the same period last year. This was driven primarily from the addition of the San Joaquin assets acquired in November 2015 and a stronger US dollar. These assets more than offset the declines we saw from Alberta Power, as spot prices were at a new record low in the quarter of approximately $18 per megawatt hour. This compares to $29 per megawatt hour in the first quarter of 2015.

As a result of the Alberta government's change to the Specified Gas Emitters Regulation, effective March 8, we exercise our right to terminate the Sundance B PPAs. AltaGas's power portfolio in Alberta now consists of 65 megawatts of natural gas fired generation, coming from our three co-generation facilities at Harmattan and a few smaller peaking units. This represents less than 4% of our total generation capacity now and is not material to AltaGas's business.

In Utilities we achieved $108 million in normalized EBITDA for the first quarter of 2016, a 4% increase over the same quarter of 2015. The growth in normalized EBITDA was driven by customer and rate base growth, combined with favorable foreign exchange, offset by significantly warmer weather at all of our utilities.

Finally, in our Gas segment, we achieved $35 million in normalized EBITDA for the first quarter of 2016, down from $47 million in the same quarter of 2015. The lower EBITDA was driven by lower extraction volumes, lower realized frac spread, as well as lower processed volumes, due to the sale to Tidewater during the quarter. Equity earnings from Petrogas were up in the quarter at CAD2 million, versus nil the first quarter of 2015, driven by the expansion of Petrogas' liquefied petroleum gas business in the U.S., as well as international markets through the Ferndale terminal.

Looking ahead to 2016, the primary drivers behind our growth in normalized EBITDA and funds from operations will be full-year contributions from our newly-acquired San Joaquin facilities, a full year of McLymont and a partial year from our Townsend shallow-cut, natural gas-processing facility.

We continue to be cognizant of the headwinds facing producers in our midstream business and we're focused on operational efficiencies, including lowering cost to producers, while maintaining high availability. We continue to make significant progress on our Northeast BC strategy, to which we are also working to deliver higher value to our customers. The Townsend facility is approximately 85% complete, and is on track to be in service by mid-2016. With the current environment and our in-house construction expertise, we expect to bring the facility in under budget.

The 25-kilometer gas-gathering line is now complete and well under budget. It is under a 20-year, take-or-pay with Painted Pony. We have under construction two liquids egress lines, and a truck terminal on the Alaska Highway. Construction of the pipelines were substantially completed in the first quarter. The liquids-egress lines have initial capacity of 10,000 barrels per day each, with potential expansion up to 30,000 barrels per day each. The lines have been sized to accommodate any future expansions of Townsend or in the area. We expect to finalize a 20-year, take-or-pay agreement with Painted Pony for all liquids for the Townsend facility. Construction activities for the truck terminal are well underway, with fabrication and earthwork starting in April. The terminal is expected to be complete in the third quarter of 2016.

Our liquids separation facility near Fort St. John is also progressing. We're calling this facility the North Pine liquids separation facility, located 45-kilometers northwest of Fort St. John. With North Pine, we can connect our existing infrastructure in the region to our Ridley Island Propane Export Terminal. We've been working closely with First Nations and other key stakeholders, and on April 14, we submitted a formal application to the B.C. Oil and Gas Commission. We are also deep into discussions with producers for backstop agreements that will underpin the facility. We expect to reach an FID later this year.

We are also in the early stages of a liquids separation facility the northwestern region of Alberta, in the Deep Basin. A pre-FEED study will be completed in May. The facility is being designed with a capacity to process up to 10,000 barrels per day of C3+ and handle up to 10,000 barrels per day of C5+. We are in active discussions with producers and have started to engage First Nations and key stakeholders. The location is, again, ideal, as it can easily tie to our Northeast B.C. infrastructure and has real connectivity to tie to our proposed Ridley Island Propane Export Terminal.

At Ridley, we have begun the formal environmental review process. Preliminary engineering has been completed and a FEED study is in progress and is expected to be completed in the second quarter of 2016. We continue to work closely with First Nations and government and key stakeholders, and expect to reach FID later this year. We're very excited about Ridley, as it brings together the full natural-gas value chain and offering for producers in Western Canada. With a design capacity to ship approximately 1.2 million tons per annum, or 40,000 barrels per day of propane, this really can be a game changer for our industry.

Throughout the entire value chain, our processing, liquid separation, storage, logistics and exports, we can offer producers lower construction costs, lower operating costs, with higher reliability and the potential for high netbacks through new markets. As mentioned previously, we have seen a significant step up in interest from producers for exports through Ridley. AltaGas will contract for the majority of the capacity, enough to assure recovery of capital in operating cost, prior to making our FID. We've also been in talks with multiple potential off-takers for our Ridley Island Propane Export Terminal. These include counterparties in Japan, Korea and China, among others. Feedback and initial discussions have been positive and we would expect to have MOUs in place, with multiple off takers prior to FID.

In our Power segment, we've had a busy quarter. We submitted a response to an RFP for the re-contracting of our Blythe facility and submitted an application with the California Energy Commission to repower our Pomona Facility. The repowering of the Pomona Facility, to a flexible fast-ramping, peaking facility positions that competitively for potential upcoming RFPs in the Los Angeles load basin. The repowered facility would be more efficient gas-fired technology, with capacity up to 100 megawatts, which is more than double the current capacity. We are starting to see increased activity in the Western U.S., which we fully expect to lead to several RFPs being issued this year and next.

We are not solely focused on California. The strategic location of our assets allows us to serve the Western power grid, including the states of Nevada, Arizona and New Mexico. As we move through 2016, we expect to bid both the existing Blythe facility, in for re-contracting, as well as the proposed Sonoran facility into upcoming RFPs in these Western U.S. states.

As we start out 2016, we have a strong, diversified base business, coupled with a healthy balance sheet. We also have a lot of exciting opportunities in front of us that we expect to come to fruition, but, as always, we will be disciplined in pursuing them. I will now pass the call over to Tim.

Tim Watson - ***AltaGas Ltd. – Executive Vice President & CFO***

Thank you, David. Good morning everyone. We continue to see the strength of our diversified business platform. Normalized EBITDA in the first quarter of 2016 was $178 million, similar to the first quarter of 2015. Utilities represented the largest component of that total, at 58% and we're up 4% over the first quarter of 2015. Power increased 34% year over year, to represent 23% of total EBITDA. And gas midstream was 19% of total Q1 EBITDA, and declined year over year.
The acquisition of the San Joaquin facilities and the impact of the stronger US dollar on our U.S. operations contributed approximately $36 million in EBITDA growth. Significantly warmer weather at all of the utilities, lower realized frac spreads and lower Alberta Power prices were what offset these gains.

We remain on track to achieve our guidance of approximately 20% growth in normalized EBITDA, and up to approximately 15% growth in normalized funds from operations for the year. To emphasize, we're not counting on a material near-term increase in commodity prices to deliver this growth.

For the first quarter of 2016, AltaGas reported normalized funds from operations of $132 million, or $0.90 per share. Down slightly from $140 million, or $1.05 per share achieved in the first quarter of 2015. Normalized FFO was down, primarily due to higher interest expense and higher contributions to AltaGas's equity account investments.

In the quarter, we received a dividend from Petrogas for approximately $6 million, which was in line with our expectations. We're reasonably confident of continued Petrogas dividends of this magnitude through the rest of 2016.

Normalized net income for the first quarter of 2016 was $38 million, or $0.26 per share, compared to $57 million, or $0.43 per share, in the first quarter of 2015. Normalized net income was lower, due to weather and commodity prices, as referenced previously, as well as higher depreciation, amortization, interest expense, and preferred share dividends.

On a US GAAP basis, we reported net income applicable to common shares for the first quarter of 2016 of $55 million, or $0.38 per share. This compares to $66 million or $0.49 per share for the first quarter in 2015. Normalizing adjustments in the first quarter of 2016 relate primarily to unrealized gains on risk management contracts and gain on sale of assets.

On February 29, 2016, we completed the disposition of certain non-core natural gas gathering and processing assets to Tidewater Midstream for $30 million in cash and 43.7 million common shares of Tidewater. The assets were primarily located in central and north-central Alberta and totaled approximately 490 MMcf/d a day of operating capacity. They accounted for less than 2% of 2016 normalized EBITDA. As part of the transaction, AltaGas recognized a pretax gain in the first quarter of 2016 of $4 million and, combined with a $10 million tax recovery, this resulted in a $14 million after-tax gain.

The acquisition of the remaining 51% interest in the Edmonton Ethane Extraction Plant on January 1, 2016, was opportunistic and strategic in nature, as it ties to our longer-term strategy for propane exports by providing greater control of supply. The 51% planned interest acquired has the potential to provide an additional 1,500 barrels a day of C3+, subject to operating decisions and market pricing, of course.

During the quarter, AltaGas, through its partnership with TransCanada, terminated the Sundance PPAs, effective March 8, 2016, a decision based on change in law provisions. AltaGas recognized a pre-tax provision of $4 million on its investment, which, together with 2015 actions, results in the investment being fully written down.

For the first quarter of 2016, interest expense was $36 million, compared to $30 million for the same quarter in 2015. The increase is driven by higher average debt outstanding, as a result of the purchase of the San Joaquin facilities, and lower capitalized interest, as assets like McLymont were brought into service. These were partially offset by lower overall interest rates.

Depreciation was $68 million in the first quarter 2016, compared to $50 million in the first quarter of 2015. This increase was mainly due to the acquisition of the San Joaquin facilities, new assets placed into service, and the impact of the stronger US dollar.

For the first quarter of 2016, income tax expense was $6 million compared to $30 million for the first quarter 2015. The decrease was mainly due to the $10 million tax recovery related to the asset sale to Tidewater, which I referred to earlier, coupled with lower earnings in the first quarter of 2016. On a full-year basis, we expect our effective tax rate to be in the 20% to 25% range.

Net invested capital in the first quarter 2016 was $151 million, compared to $131 million in the first quarter of 2015. This is primarily comprised of increases in property, plant and equipment, coming primarily from construction costs related to the Townsend facility and the purchase of the remaining of 51% in the Edmonton Ethane Extraction Plant, partially offset by the sale of the FG&P asset to Tidewater. There was also an increase in long-term investments relating primarily to AltaGas's investment in Tidewater.

AltaGas' balance sheet is in a strong position and we are fully funded for 2016. At the end of the first quarter of 2016, debt to total capital was 48%, well below our covenant levels of 65% to 70%, yet the debt to total capital is in line with historical levels. We've approximately $1 billion available on our credit facilities and, as we demonstrated over this past month, we have great access to multiple sources of funding. More specifically, in early April, we did a very successful 10-year, $350 million medium-term note offering, at an attractive coupon of 4.12% and, yesterday, we announced we will be implementing a premium-dividend reinvestment plan, along with changes to the dividend reinvestment plan. As we previously have indicated, the DRIP results in up to $100 million of additional funds annually, and the premium DRIP may achieve up to $40 million in the balance of 2016.

Turning to our 2016 outlook by major business line, I will start with Power. North American Power portfolio is now approximately 95% contracted, with 100% of generation coming from clean energy sources. The power segment is expected to contribute approximately 42% of our overall forecasted normalized EBITDA for the year, with strong year-over-year growth. This will be driven by the addition of the San Joaquin facilities, acquired late last year, as well as a full year of contribution from the McLymont Creek hydroelectric facility, and we're benefiting also from the strong US dollar on our U.S. power assets. So, as overall, as we stated before, the Alberta Power exposure is not material at this point to our ongoing results.

In terms of our Alberta Power portfolio, it now includes only 65 megawatts of natural gas-fired generation. That's primarily the co-gen units and the small peaking facilities; they represent only 4% of the total generation portfolio. Alberta Power price exposure on the remaining power portfolio, for the remainder of 2016, is hedged, resulting in no variability to Alberta Power pool prices.

Our utility segment is expected to contribute or account for 37% of normalized 2016 EBITDA, which, with moderate growth expected this year. This is driven by rate-based customer growth, while also benefiting from a favorable US dollar. In Michigan, Semco gas expects approximately CAD8 million of additional margin in 2016, as a result of the full-year contribution of its main replacement program. In Alaska, the Regulatory Commission of Alaska has accepted ENSTAR's 2015 filing, resulting in an increased total margin of CAD6 million in 2016. These will be partially offset by changes made by Heritage Gas to its rate structure to remain competitive, in terms of pricing and customer retention.

Finally, the gas midstream segment is expected to have a moderate decline in EBITDA on a year-over-year basis. Overall, we expect our midstream business to account for approximately 21% of 2016 normalized EBITDA.

Our integrated Northeast British Columbia strategy is expected to add additional EBITDA to our gas segment in 2016, as the Townsend facility enters commercial operations mid-year. Townsend facility is expected to generate normalized EBITDA of approximately $15 million-$20 million for 2016, once commercially on stream, as volumes from Painted Pony progressively increase through year-end.

We also expect to see strong results from Petrogas in our gas midstream segment and part of this will be driven by continued strong performance at the Ferndale LPG facility, which AltaGas operates on the U.S. West Coast. The absence of turnarounds at the Harmattan and Younger extraction plants in 2016 will also add to performance. However, this is expected to be offset by lower contributions from commodity prices, the sale of the Tidewater gas assets, and moderately lower FG&P volumes.

Today our FG&P business is increasingly focused on larger core-infrastructure assets in Northwest Alberta and Northeast B.C., supported by sustainable Montney development. This includes the Gordondale, Blair Creek and Townsend facilities, all of which are supported by attractive take-or-pay arrangements. In Q1 2016, the core Gordondale and Blair Creek aggregate volumes were approximately 176 million, and the balance of total FG&P volumes excluding the Tidewater disposition; we're about 102 million a day, in terms of volumes.

Gordondale, Q1 2016 volumes were flat year-over-year. Blair Creek volumes were actually up 16%, and other FG&P volumes were off 3%. With the full year in 2017 for the Townsend facility, volumes from these three core FG&P assets will represent over three-quarters of total FG&P volumes in the company. Within gas midstream, overall, and that includes FG&P and extraction, take-or-pay contracts represent approximately 44% of 2016 EBITDA in midstream. Cost of service is 22% of total midstream EBITDA. Fee for service is 26%, leaving about 8% that has direct commodity exposure. This 8% in the gas midstream segment represents just slightly less than 1% of total 2016 expected corporate normalized EBITDA.

The weighted average term of the take-or-pay contracts in our portfolio is 17 years, while cost-of-service contracts averaged 10 years. Again, for some sensitivity analysis, every plus or minus-10% change in gas volumes impacts total corporate EBITDA by $7 million to $10 million, which is about 1% of our total expected EBITDA for this year.

As I stated before, within AltaGas's gas midstream segment, a majority our customers across a widely diversified portfolio have investment-grade credit ratings. Based on Q1 2016 results, no material allowances have been incurred and receivables are very consistent with historical experiences.

Within the overall gas midstream segments, approximately 5% of our '16 expected EBITDA, exposed to commodity prices for this year. Based on current commodity prices, we expect to have approximately 2,000 barrels a day of extraction volumes exposed to frac spread for the remainder of 2016. To put this in perspective, this represents about 3% of total-produced extraction volumes with AltaGas, demonstrating the low amount of frac spread exposure for the duration of the year.

During the first quarter 2016, there were no NGL frac hedges in place. In terms of hedging for 2016, subsequent to the end of the quarter, we did enter into summer and winter frac hedges with bifurcated volumes ranging from 750 to 3,000 barrels per day, at an average price of $22 per barrel, excluding basis differentials. If, however, frac spreads do recover, and we have seen some improvements in this past quarter, AltaGas is well positioned to deliver additional normalized EBITDA growth, as we can increase the production of exposed C3+ production, but we are not counting on that in our 2016 expectations.

It is also important to remember that 50% of our EBITDA does come from the U.S.. This shows or highlights, our diversified business platform. Some of this US dollar exposure is naturally offset by our depreciation in the U.S., our interest on U.S. debt, and dividends from US-denominated preferred shares and tax expenses.

Again, for sensitivity purposes, for every plus or minus-5% change in the Canadian/US Foreign Exchange Rate, the annual EBITDA impact is about $14 million, so that's about the same as what we gave you in our previous quarterly call for the end of 2015.

Getting close to wrapping up here, in terms of total expected capital expenditures in 2016, we continue to believe and expect that we will be between $550 million and $650 million this year. This is predominantly related to growth, in particular the completion of Townsend and its associated infrastructure, as well as investments in our regulated utilities. We also expect to restart construction, on our Alton natural gas storage project in the summer, and have some spend in moving our Ridley Island Propane Export Terminal and our North Pine liquids separation facility forward later this year, subject to FID.

Maintenance capital for gas and power businesses in 2016 is expected to be less than $40 million. We expect, again, just for guidance here, approximately $290 million for depreciation, amortization, and accretion expense for 2016. Depreciation will increase over 2015 levels to account for the McLymont and San Joaquin power assets and other additions to our infrastructure portfolio.

So, in summary, the San Joaquin facilities, Townsend, McLymont Creek, Alton and our future capital investments in our regulated utilities business, are all expected to result in approximately a 50% increase in AltaGas's normalized EBITDA by 2020, relative to 2015 normalized EBITDA of $582 million. Any discretionary development capital for other projects referenced is beyond those numbers, and will only serve to further increase our future EBITDA growth.

To wrap up, 2016 looks to be a very promising and busy year for AltaGas, a year where we expect to deliver strong shareholder returns, since we drive approximately 20% growth in normalized EBITDA, and up to 15% in normalized funds for operations.

We're moving a lot of exciting growth opportunities forward, and I will now turn it back to Jess.

Jess Nieukerk - *AltaGas Ltd. - Director of Finance and Communications*

Thank you, Tim. Operator we will now open it up to the investment community for questions and answers.

QUESTION AND ANSWER

Operator

First question is from David Allison of Canaccord Genuity. Please go ahead.

David Galison - *Canaccord Genuity - Analyst*

Good morning. My first question really just relates to your development project pipeline. For these projects to receive final investment decision, can you talk a bit about what type of return profiles you are targeting for them?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Yes. Happy to, David.

In terms of our expectations, we talk about generally IRR. IRR is typically how well most folks in this energy infrastructure look at new projects and we would be probably in the 8% to 10% range on those sorts of types of projects, a real tradition from how we have looked at things historically. We do look, and I think we do have in our investor slides that are on our website, some expectations for the amount of expected capital and the likely investment ratio that would arise from that investment capital on certain new projects including Townsend, and others.

David Galison - *Canaccord Genuity - Analyst*

Okay. Just on the EEEP, according to the remaining interest, you said it's around at the potential of adding an additional 1,500 barrels per day?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Yes it has the potential to, yes.

David Galison - *Canaccord Genuity - Analyst*

Okay. And, then, that's more just around what market conditions, you know, if it warrants producing that oil at that level?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

That's correct. The plants are very flexible and, I think, as David mentioned, we have the ability to re-inject or turn them on effectively from our volume standpoint, in short order and to react to market conditions and hedges we have in place, et cetera.

David Galison - *Canaccord Genuity - Analyst*

Okay thanks very much.

Operator

Robert Kwan, RBC Capital Markets.

Robert Kwan *- RBC Capital Markets - Analyst*

Good morning. Just looking at North Pine and, you've got the expected EBITDA multiple there at 8 to 9 times. Is that kind of what you would expect on a fully-contracted basis? Or what level of contracting are you looking at for that type of facility? Essentially, what's underlying the 8 to 9 times?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Yes, that would be based on the facility being on a full-run rate, to fully-commercialized in an operation, and with underpinning that we would expect for all our projects, including that one.

Robert Kwan - *RBC Capital Markets - Analyst*

Okay, and so would you need that level, then, of contracting going in, or are you comfortable with being something somewhat less than that and kind of filling it up over time? And, I don't mean on a contract, like on a, you know, taking a little bit of extra exposure, but feeling good that you would fill it up?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Yes, I mean, I think, ultimately, the way we view projects, we view them on a full-cycle basis. If there's a justification for the project and it has strategic merits and, based on feedback we received, we ultimately do expect to have them running close to full and being fully supported from a contractual standpoint.

You know North Pine, to use your example, is, we view it as a regional project. It's not going to be a single exposure or a single counter party or single producer on the upstream side. It will be multiple producers and, so, that, in itself, is an important differentiating feature, versus, say, a plant that is typically associated with a single producer.

When we think about 2016, and advancing the project from a permitting and development standpoint, commercial will move along in a similar parallel path. We don't necessarily need to, nor necessarily expect, to have a full-contractual underpinning by the end of year, because in a normal-course development cycle, with an on-stream date in the first half of 2018, there would be continued progression over those two years.

And, again, it's not dissimilar to other projects we've undertaken in the past. This shouldn't be any different from a development standpoint.

Robert Kwan - *RBC Capital Markets - Analyst*

Okay, and you mentioned multiple producers. And, I think you've disclosed that about 70% of your customers in the gas segment are investment-grade. Would that be a very similar makeup, in terms of credit rating, as well as the size of customers that might be coming into North Pine?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

You know, I think that there is a mixture and I think probably most folks on the phone are going to be familiar with Northeast B.C. activity, which is typically Montney driven, as you can imagine, but there's a whole mix of producers in that region. There's public, there's private, there's large caps, there's multinationals. And there are smaller ones as well.

So it's really just microcosm of Western Canadian basins. I'm not trying to be -- duck the question at all. It’s simply that the reality is we are in discussions with multiple parties and they would fit right across the whole spectrum.

Robert Kwan - *RBC Capital Markets - Analyst*

Okay. If I could just turn to a question here on funding.

Tim, you mentioned you're fully funded for 2016. And you've got lots of liquidity sources. I'm just wondering if you had additional discussions there with S&P on how to resolve the negative rating outlook?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

We haven't had any recently, but that's in part because we had a very comprehensive discussion, a series of discussions, through end of last year. And, I think, I might've said this, for sure I did, actually, on the previous year-end conference call, that we have a very open relationship, open book with them, and we've got some specific objectives now coming out of that.

It's more on to us now, to plan our course of actions for this year as well as next year. I think that's a timeframe we are thinking about in terms of addressing some of those concerns.

Robert Kwan - *RBC Capital Markets - Analyst*

So, it sounds like there are things that you need to do to resolve the negative rating outlook, i.e., the current, or put differently, kind of a do nothing other than continue to execute the commercial side is not enough to remove negative outlook?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Well, I think when we think about just running the company, which is really what management's tasked to do, the status quo is never a scenario, but I think when we look to grow the company and fortify the company, many of those steps that we would be doing in normal course, and that includes things like North Pine and RTI. On a development side, they are actually creating certain measures, including things like FFO-to-debt.

So, it's part of our normal planning process. And, that's how we think about it, Robert.

Robert Kwan - *RBC Capital Markets - Analyst*

Okay that's great thanks very much.

Operator

Linda Ezergailis, TD Securities.

Linda Ezergailis *- TD Securities - Analyst*

Thank you.

I am wondering if you could clarify on the Blythe RFP. Was that for the full 507 megawatts that you submitted, and when we do expect to hear back?

John O'Brien *- AltaGas Ltd. - President AltaGas Services US*

This is John O'Brien, Linda.

That was for the full Blythe facility and, as we look at RFPs going forward, we think in terms of the full Blythe facility. I think on this RFP, we're on a fairly tight timeline to hear back. We may hear back in the next four to five weeks on this, according to the timeline we got.

So, I don't know that -- we are not in control of the RFP, certainly, so that's what we would estimate as a timeline. But it was for the full amount of megawatts out of the facility.

Linda Ezergailis - *TD Securities - Analyst*

Thank you.

And just moving to the other part of the continent, for Alton, what's causing some of the delays there? Is there some NIMBY-ism? Is there some commercial considerations that have delayed some of the activity there?

David Harris - *AltaGas Ltd - President & CEO*

No, commercially there is no real concerns. What we are doing is some timing; we've got the progress we need to turn it around and move forward on the project.

And seasonality comes into play when we want to start the activity, with respect to some of our environmental limitations on construction. And we'll be looking to move into construction on that project, as we get into around the midsummer timeframe.

Linda Ezergailis - *TD Securities - Analyst*

Okay, thank you.

And can you just maybe also comment -- I realize it's just kind of more a cleanup question -- what other sorts of non-core assets are you considering monetizing?

David Harris - *AltaGas Ltd - President & CEO*

We would potentially look at some of our additional other, maybe non-core, smaller FG&P assets, consistent with what we have just recently done with Tidewater, but nothing specific at this time.

Linda Ezergailis - *TD Securities - Analyst*

Okay, great.

And maybe just on the quarter, can you talk about the dollar effect of the unusually warm weather? What utilities EBITDA would have been if weather would've been normal in the quarter?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Don't know if I've got a specific, hard number to give you on that. I am thinking out loud as I do this. As you know, it was right across all the utilities and maybe in rough terms -- and this would be sort of EBITDA on an EBITDA basis -- you can say around $15 million. That would be sort of an aggregate impact.

Linda Ezergailis - *TD Securities - Analyst*

Great.

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

That is a soft number, but probably representative here.

Linda Ezergailis - *TD Securities - Analyst*

Great thank you.

Operator

Ben Pham, BMO Capital Markets.

Ben Pham *- BMO Capital Markets - Analyst*

Thanks, good morning everyone.

I wanted to clarify the $15 million you highlighted with the utilities. Was that in your expectations with your guidance, to some extent?

I am sorry, I got on the call a little bit late, you're maintaining your guidance, but was the Q1 in line with your expectations, broadly speaking?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

No, we do not forecast weather, other than on a normal basis. So the $15 million would not have been a factor.

Ben Pham - BMO Capital Markets - Analyst

Okay, so your guidance is on a normalized basis? You stripped the weather out. You assume it's normal weather?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

Yes, I mean, the weather is extremely unpredictable. When we were thinking about going back to Q4, when we start to think about what 2016 is going to look like, and as we get into Q1, even, we are not adjusting to try to real time what the actual weather is offset to that.

One of the things that are positive will be things like the FX, to partially offset some of that, at least from a U.S. utilities perspective.

Ben Pham *- BMO Capital Markets - Analyst*

Okay great.

If I may, a broader question. I was just wondering about -- how does your broader contracting strategy when you think about your business, because the utility side, that's professional cash flows, and the power side could be 70 years to 60 years on some of your power stuff and in the gas side, mix different contracts, depending on the structure? Do you think you build your business more broadly from a contracted perspective, where if you're adding longer contracts in one segment, you can take lower contracts on other? Do you look at each of the individual segments on a separate basis?

Tim Watson - *AltaGas Ltd. – Executive Vice President & CFO*

They are all very different, clearly. It's a good question, but -- and they're all very different and we do view them as complimentary and perhaps that gives us some flexibility, in terms of how we think about it. But utilities are just plain utilities and are regulated, as you said. Our philosophy on power is to be contracted. And that's what we have achieved.

So, when you look at the gas midstream side, the remainder -- the reality in Western Canada is, you typically do see a variety of different types of contracts. And what we have with our portfolio is not a whole lot different from what other true midstream companies that have a bit of a diverse midstream business, what they would have themselves.

So that mix I talked about earlier, take or pay, cost of service, fee for service, and then, frankly, some, any commodity exposure beyond that, that's typically what you end up with, given a mix of midstream assets. I mean, we have some smaller pipelines, we have some newer FG&P plants, we have extraction and all those come with different types of contracts; it's what we expect. And we do look to try to take volatility out where we can and we've done that.

For example, on our largest extraction asset, that's Harmattan, we have a healthy element of a sort of a cost-of-service arrangement on that plant, which is significant in mitigation and volatility. So that's just an example, I guess.

Ben Pham - ***BMO Capital Markets - Analyst***

Okay. Another question I had, lastly, on the California power side. What will drive the additional RFPs you highlighted? Is that the utilities that are gearing up for long-term resource plans? Maybe a bit more color there.

John O'Brien - ***AltaGas Ltd. - President AltaGas Services US***

Yes, sure, this is John O'Brien, again.

I think, as Dave highlighted, Dave Harris' opening, its more looking at the Western states. So, that, when we think of, as an example, the Blythe facility, from a transmission perspective, we anticipate that other states, in addition to California, will have power needs. And so that's how we look at life and the development sites we have there.

So, it's a Western-states perspective, I would say, and not just a California perspective, as we anticipate what will come.

David Harris - ***AltaGas Ltd - President & CEO***

And we are aware, right now, if I'm correct, four RFPs that will be forthcoming both this year and early part of next year.

John O'Brien - ***AltaGas Ltd. - President AltaGas Services US***

In the next year.

David Harris - ***AltaGas Ltd - President & CEO***

That's correct.

Ben Pham - ***BMO Capital Markets - Analyst***

Okay great; thanks for taking my questions.

Operator

There are no further questions registered. I will like to turn the meeting back over to Mir. Jess Newkirk. Please go ahead, Sir.

Jess Nieukerk - AltaGas Ltd. ***- Director of Finance and Communications***

Thanks, John.

I would like to thank everybody for joining us today. We are available for any follow-up calls afterwards. Thank you.

Operator

Thank you. The conference call has now ended. Please disconnect your line at this time. We thank you for your participation.