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ONTARIO ENERGY BOARD

FILE NO.: **EB-2017-0319** **Enbridge Gas Distribution Inc.**

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DATE: **June 27, 2018**

EB-2017-0319

THE ONTARIO ENERGY BOARD

Enbridge Gas Distribution Inc.

Application for approval of the cost consequences of the proposed Renewable Natural Gas Enabling Program and Geothermal Energy Service Program

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Wednesday, June 27, 2018,
commencing at 9:34 a.m.

TECHNICAL CONFERENCE

A P P E A R A N C E S

LAWREN MURRAY	Board Counsel
SHUO ZHANG LAURIE KLEIN	Board Staff
DAVID STEVENS JOEL DENOMY	Enbridge Gas Distribution Inc.
LISA (ELISABETH) DeMARCO	Anwaatin Inc.
JOHN VELLONE	Association of Power Producers of Ontario (APPrO)
MICHAEL BUONAGURO	Balsam Lake Coalition (BLC) Arbourbrook Estates
JULIE GIRVAN	Consumers' Council of Canada (CCC)
BRADY YAUCH	Energy Probe Research Foundation
DWAYNE QUINN	Federation of Rental-housing Providers of Ontario (FRPO)
IAN MONDROW	Industrial Gas Users' Association (IGUA), Enwave
MICHAEL BUONAGURO	Canadian Biogas Association (CBA) and Ontario Greenhouse Vegetable Growers (OGVG)
MARION FRASER	Ontario Sustainable Energy Association (OSEA)
MARK RUBENSTEIN	School Energy Coalition (SEC)

I N D E X   O F   P R O C E E D I N G S

Description	Page No.
--- On commencing at 9:34 a.m.	1
Appearances	1
ENBRIDGE GAS DISTRIBUTION INC. - PANEL 1 **A. Chagani, S. McGill, M. Giridhar**	3
Presentation by Ms. Giridhar	3
Examination by Ms. Klein	7
Examination by Ms. DeMarco	43
--- Recess taken at 11:33 a.m.	72
--- On resuming at 11:57 a.m.	72
Examination by Mr. Vellone	72
Examination by Mr. Buonaguro	100
--- Luncheon recess taken at 1:05 p.m.	111
--- On resuming at 1:55 p.m.	111
Examination by Ms. Girvan	111
Examination by Mr. Yauch	123
Examination by Mr. Mondrow	154
--- Recess taken at 3:49 p.m.	180
--- On resuming at 4:02 p.m.	180
Examination by Mr. Rubenstein	180
--- Whereupon the hearing concluded at 4:39 p.m.	197

E X H I B I T S

Description	Page No.
EXHIBIT NO. KT1.1: BOARD STAFF TECHNICAL CONFERENCE QUESTIONS	7

U N D E R T A K I N G S

Description | Page No.

UNDERTAKING NO. JT1.1: TO PROVIDE THE DECISIONS AND THE RELATED PROGRAMS ACROSS THE COUNTRY INCLUDING ONTARIO, QUEBEC, AND TCPL'S RELATED TO RNG. ALSO TO PROVIDE MONTHLY CHARGES IF FOUND. 14

UNDERTAKING NO. JT1.2: TO PROVIDE THE GHG CALCULATION AND RELATED INFORMATION, IN RELATION TO OEB STAFF TEHCNICAL QUESTION #3. 17

UNDERTAKING NO. JT1.3: TO PROVIDE INFORMATION ABOUT AND/OR COPIES OF DRAFT REGULATIONS IF AVAILABLE THAT OUTLINES THE REGULATIONS TO SUPPORT BIOGAS INJECTED IN ONTARIO TO BE USED BY COMPANIES IN WA; TO FILE PUBLIC DOCUMENTS FOR COMMENT ON THE CLEAN FUEL STANDARD FROM CANADA AND THE PUBLIC COMMENTS ON THE DRAFT RENEWABLE FUEL STANDARD FROM ONTARIO, FILED ON THE RESPECTIVE RFS AND CFS PROGRAMS. 26

UNDERTAKING NO. JT1.4: TO PROVIDE A DELINEATION OF ENVIRONMENTAL ATTRIBUTES, WHO GETS WHAT AND HOW THE CALCULATIONS WORK. 33

UNDERTAKING NO. JT1.5: TO PLEASE PREPARE AN ANALYSIS THAT DERIVES THE LEGALIZED SERVICE FEE THAT IS EQUIVALENT TO THE REVENUE REQUIREMENT (APPENDIX 6, LINE 15) ON THE PRESENT VALUE BASIS OVER THE SERVICE LIFE OF THE ASSET. 41

UNDERTAKING NO. JT1.6: TO PROVIDE THE CHARTS WITH THE ASSOCIATED CARBON ABATEMENT SAVINGS OR REASONABLE ESTIMATE THEREOF. 51

U N D E R T A K I N G S

Description	Page No.
UNDERTAKING NO. JT1.7: (1) TO PROVIDE THE POTENTIAL GREENHOUSE GAS REDUCTIONS DIRECTLY FROM BIOGAS PRODUCERS; (2) TO QUANTIFY THE EMISSION REDUCTIONS, OR THE DECREASED EMISSION REPORTING ASSOCIATED WITH THE POTENTIAL SUBSTITUTION VALUE, IF YOU CAPTURED THIS; (3) TO ATTEMPT TO QUANTIFY THE POTENTIAL RIN OR OTHER ENVIRONMENTAL ATTRIBUTES ASSOCIATED WITH WHAT YOU ARE ALLOWING TO BE INJECTED, IN TERMS OF RINS OR OTHER ENVIRONMENTAL INSTRUMENTS THAT HAVE VALUE.	58
UNDERTAKING NO. JT1.8: TO PROVIDE THE ANALYSIS THAT WENT INTO DETERMINING THAT THE UPGRADING SERVICE WAS A NON-OBLIGATORY SERVICE BUT THE INJECTION IS MANDATORY.	61
UNDERTAKING NO. JT1.9: TO ADVISE WHETHER ENBRIDGE HAVE EVER HAD A SHAREHOLDER RESOLUTION RELATING TO ITS GREENHOUSE GAS POSITION.	62
UNDERTAKING NO. JT1.10: RE: THE POTENTIAL CORPORATE-WIDE EMISSION REDUCTIONS FROM UNDERTAKING JT1.9, TO PUT THAT IN THE CONTEXT OF THEIR CORPORATE-WIDE EMISSIONS; HOW SIGNIFICANT IT IS TO THE CORPORATE-WIDE GREENHOUSE GAS EMISSIONS.	62
UNDERTAKING NO. JT1.11: TO PROVIDE A MAP OF THE PROPOSED LOCATIONS REFERRED TO AT EXHIBIT B1.1, PAGE 11, PARAGRAPH 32; TO PROVIDE A SECOND MAP OVERLAYING THE FIRST NATIONS AND INDIGENOUS COMMUNITIES IN THOSE SAME AREAS, FOR THE UPGRADING SERVICES AND THE INJECTION SITES.	63
UNDERTAKING NO. JT1.12: TO ASK ENGINEERING EXPERTS ABOUT THE SMALLEST SIZE INJECTION STATION THEY COULD PUT IN, AND ESTIMATE A COST, ASSUMING THE RNG PRODUCER IS RIGHT THERE AND ASSUMING A MINIMUM AMOUNT OF PIPE	70

U N D E R T A K I N G S

Description	Page No.
UNDERTAKING NO. JT1.13: TO PROVIDE THE REGULATORY PRECEDENTS FROM THE OTHER JURISDICTIONS; TO PROVIDE AN ANALYSIS OF THE TWO MARKETS	79
UNDERTAKING NO. JT1.14: TO CONFIRM WHETHER REGULATORY COSTS ARE INCLUDED IN CAPITAL COSTS THAT MAY BE INCURRED IN BRINGING FORWARD A LEAVE TO CONSTRUCT PROCEEDING FOR APPROVAL; TO PROVIDE MODEL PROJECTS SHOWING EXPECTATIONS OF WHAT THOSE COSTS WOULD BE	193
UNDERTAKING NO. JT1.15: TO ANSWER THE FOLLOWING QUESTION: WOULD YOU AGREE TO LANGUAGE IN THE RATE HANDBOOK, YOUR CONDITIONS OF APPROVAL, FOR INCLUSION THAT WOULD REQUIRE SUFFICIENT FINANCIAL ASSURANCES FROM PRODUCERS TO COVER ALL UNDEPRECIATED COST OF THE ASSETS' REMOVAL SITE REMEDIATION IF IT WAS SPECIFIC TO PRIVATE ENTITIES?	197

Wednesday, June 27, 2018

--- On commencing at 9:34 a.m.

MR. MURRAY: Good morning, everyone. I think it is probably a good time to get started.

This is the technical conference for OEB file number EB-2017-0319, which is Enbridge's application for approval for the cost consequences of two proposed programs: Its renewable natural gas enabling program and its geothermal energy service program.

My name is Lawren Murray. I am OEB counsel. With me from OEB staff are Laurie Klein and Shuo Zhang.

Before we get started I have one preliminary matter, but before we even address that I think it might be helpful to go through appearances. Perhaps we could start with Mr. Stevens.

APPEARANCES:

MR. STEVENS: Thanks, Lawren. I am David Stevens. I am here as counsel with Enbridge, and sitting with me is Joel Denomy.

MS. DeMARCO: Lisa DeMarco. I'm here on behalf of the Anwaatin First Nations communities.

MS. FRASER: Marion Fraser. I am here on behalf of OSEA.

MR. MONDROW: Ian Mondrow, counsel for the Industrial Gas Users Association. I am also here as counsel for Enwave, but I don't expect in that respect I will be active today.

MR. VELLONE: Good morning. John Vellone, counsel for the Association of Power Producers of Ontario.

MR. YAUCH: Good morning, Brady Yauch on behalf of Energy Probe Research Foundation.

MS. GIRVAN: Julie Girvan on behalf of Consumers Council of Canada.

MR. BUONAGURO: Michael Buonaguro. I am counsel for the Canadian Biogas Association and the Ontario Greenhouse Vegetable Growers.

MR. RUBENSTEIN: Mark Rubenstein, counsel for the School Energy Coalition.

MR. QUINN: Dwayne Quinn on behalf of FRPO.

MR. MURRAY: Thank you. Now, having completed appearances I want to raise one preliminary issue. Everyone should have received a letter yesterday from Enbridge to the Board asking that the part of their application relating to the geothermal energy service program be held in abeyance at the current time. People should also have received a letter back from the Board confirming that that portion of the program will be held in abeyance, and so therefore the questions at today's technical conference should be limited to the RNG aspects of the application and questions about the geothermal are not to be asked today.

I'm not sure if anyone has any questions or comments or wants to make any statements. If so, now is a good time, otherwise we can get going with Mr. Stevens introducing the panel.

MR. STEVENS: Jump in quick. Good morning, everybody.

I will just briefly introduce the three witnesses from Enbridge today for the RNG portion of this application, and then the witnesses have just a brief sort of -- some brief introductory remarks.

So starting closest to Madam Reporter we have Abbas Chagani. Abbas is a specialist in the business development group. In the middle we have Steve McGill, who is the technical manager in the business development group, and finally we have Malini Giridhar. Malini is vice-president, market development, regulatory, and public affairs with Enbridge Gas.

And with that, I will turn it over to the witness panel.

ENBRIDGE GAS DISTRIBUTION INC. - PANEL 1

Abbas Chagani

Steve McGill

Malini Giridhar

PRESENTATION BY MS. GIRIDHAR:

MS. GIRIDHAR: Good morning, everyone. So what we will do is quickly tell you what portions of the evidence we will each be speaking to, so I'm here to talk to sort of policy issues and, in particular, some of the recent turn of events that have occurred in Ontario and what it means for some of these programs.

MR. McGILL: I'm Steve McGill, and I was actively involved in the development of both our geothermal energy service and RNG enabling program businesses, and I've also been looking after our community expansion program as well.

I'm here today to speak to general questions about our RNG proposal and some of the rationale behind that.

MR. CHAGANI: Good morning. My name is Abbas Chagani. I'm here to speak about the technical and financial modelling aspects of the RNG application.

MS. GIRIDHAR: So first I do have a brief statement concerning the company's letter of June 25th that was already referred to. As noted in the letter to the Board on June 25th, Enbridge remains committed to abating carbon emissions and to supporting the expansion of geothermal energy systems for Ontario homeowners and others.

However, given the impending change in the Ontario government and pronouncements made by members of the incoming government regarding the cancellation of the province's cap-and-trade program and the Green Ontario Fund programs, Enbridge is of the view that it is prudent to temporarily set aside a portion of this application concerning its geothermal energy service program at this time.

However, Enbridge is of the view that the circumstances concerning renewable natural gas are different, in that a market for RNG and its environmental attributes already exists in British Columbia, Quebec, and other parts of North America.

Further, some potential Ontario biogas producers, particularly some municipalities, have an interest in upgrading biogas into RNG for their own use as a means of achieving the goals of their community energy plans, and in the event that cap-and-trade is wound down Enbridge will be seeking a new variance account to record and clear the annual sufficiency/deficiency associated with the RNG enabling program.

Finally, the federal government is proposing the introduction of the Clean Fuel Standard, known as CFS, as a regulation under the Canadian Environmental Protection Act, or CEPA, and this regulation is expected to be completed in the fall of 2019 for enforcement in 2021/'22, and I would like to explain why this is relevant.

Enbridge and the Canadian Gas Association, CGA, are engaged in this process, and we understand that CFS will be distinct from and apply over and above carbon pricing.

What CFS seeks to do is to regulate the reduction of carbon intensity of fossil fuels from production to end-use. In other words, the government will establish a baseline for carbon intensity and then require reductions in their carbon intensity all the way from production to end-use.

So the expectation is that qualifying measures for CFS will relate to -- relating to natural gas will include renewable natural gas, hydrogen, methane capture, fuel switching, and carbon capture.

Interestingly, what we also understand about CFS is that there will be a market mechanism, but you cannot comply simply by procuring a market instrument. That would be limited to, say, 30 or 35 percent of the production, so you can't claim somebody else's reduction in carbon intensity as your own. Each participant would actually have to reduce the carbon intensity related to their activity.

So the CGA is participating on behalf of the natural gas industry to ensure that, you know, the regulations are appropriate, but we're also seeking federal funding for renewable natural gas similar to the funding provided for renewable electricity and biofuel industry in the past.

It is important to note that other jurisdictions such as B.C. and Quebec already have regulatory mechanisms to facilitate RNG and also have RNG facilities in operation. What this means is that not moving forward with the RNG enabling service at this point puts Ontario ratepayers at a disadvantage relative to other jurisdictions should these regulations on reducing carbon intensity become enforceable and should funding to comply become available, hence the urgency to proceed with this at this point in time.

Also note that not moving forward at this time puts Ontario biogas producers, particularly municipalities that already have projects in execution or in planning phases, at a disadvantage.

Over the course of the next few weeks the company will review its geothermal energy service program proposal, consult with stakeholders, and other interested parties with respect to the implications of the incoming government's policies as they relate to this proposal. Once this work is completed, Enbridge anticipates bringing forward updated evidence in support of its geothermal energy services program that will address the changes in the government's climate change and carbon pricing policies.

As indicated in our letter to the Board, we anticipate that we will provide an update to the Board concerning the geothermal energy service proposal on or before August 31st, 2018.

So with that, we will be available for questions.

MS. KLEIN: Board Staff have a number of questions. We circulated them yesterday, I believe.

MR. MURRAY: The draft questions that were circulated by OEB Staff will be marked as an exhibit, Exhibit KT1.1.

EXHIBIT NO. KT1.1: BOARD STAFF TECHNICAL CONFERENCE QUESTIONS

EXAMINATION BY MS. KLEIN:

MS. KLEIN: The first question, A: Given that Enbridge's upgrading service is an optional service and other companies can provide this type of service to Ontario RNG producers, please explain why the upgrading service could not be offered by an affiliate of Enbridge Gas.

MR. McGILL: So I guess the short answer is that the service could be offered by an affiliate of Enbridge Gas Distribution. We don't believe that that would be an appropriate way to do that, given that the cost for the service would end up being significantly higher if done by an affiliate, or another party in the marketplace, given that that business or program would need to compete, in the case of Enbridge internally, for capital against other projects and result in a higher cost of capital that would need to be recovered through the rates charged for the service.

So I don't know if you want to go through -- you've got your other sub points there...

MS. KLEIN: Can you please explain why it would be a higher cost than if it's between a regulated and an affiliate?

MR. McGILL: Well, the regulated utility has an Ontario Energy Board-approved rate of return, which is the target return that we set our rates to recover, and that results in an overall cost of capital that those rates recover, whereas if you're working in an affiliate or otherwise in the competitive market, you are going to be competing for those sources of capital and depending on what projects are available or lines of business are available at any given point in time. You will probably find that you would have to incur a higher cost of capital in order to have those projects go ahead.

MS. KLEIN: Okay. So in terms of i.e. the business model change, and that would be the business model change would be competing internally with other capital projects within the affiliate?

MR. McGILL: Well, I think that's an element or a consideration that would come into an account if an affiliate or another party were to consider offering a service like this.

We don't know what that service would look like, or how similar it would be to what we are offering here. As far as we know, what we are doing is somewhat unique. But there are many different ways you could construct a business model to provide all or part of these services, or bundle them up in different ways, and I can't really comment on that, and they would vary from one party to the next.

MS. KLEIN: Okay. I'm sort of jumping around, but you were saying that it would be very different. So in B.C. and Quebec, they don't offer, let's say, a monthly fee? It can't be done on a monthly fee basis if it's done by your affiliate?

MR. McGILL: Well again, in other models, you could have a volumetric fee; you could have a flat monthly fee, as we're proposing. It would all depend on the goals and the views of those parties that may want to participate in this type of business.

MS. KLEIN: So it can be done similar to the regulated in terms of a monthly fee; it depends?

MR. McGILL: That's right. And as far as we know, there are no other parties offering a service that's comparable to what we are proposing here.

MS. KLEIN: Okay. So for A3, please explain whether RNG producers would be impacted by who offers upgrading service, EGD's affiliate or the regulated utility?

MR. McGILL: Yes, and, you know, what we've indicated like earlier is that you would have this competition for capital that would likely result in higher costs, if this were undertaken through an affiliate company or other third parties.

And then the other thing is that if a business was to take this on a stand-alone basis, it's not likely that they would, I guess, enjoy the benefits of the accelerated capital cost allowance associated with investments in biogas upgrading equipment and facilities.

So, you know, in order to gain the advantage of the accelerated capital cost advantage, you have to have income from other sources in order to apply that tax deduction against. So in order to achieve that, it would need to be a fairly large organization that already has an ongoing taxable stream of income in order to take advantage of that which, fortunately, we're in a situation where we can.

MS. KLEIN: Okay, question number 2.

MR. McGILL: Yes?

MS. KLEIN: If you could describe the RNG programs in B.C. and Quebec, how they are similar and how they are different?

MR. McGILL: Okay. So the current program in British Columbia is very similar to what we are proposing here. The principal difference is that in British Columbia, Fortis B.C. and the regulator there, the BCUC, has linked the procurement of renewable natural gas together with the process of upgrading the raw biogas to pipeline quality and injecting it into the baseline system.

So all of the costs associated with doing that -- well, take a step back. The upgrading piece is largely an optional part of the process, similar to what we are proposing here. But all of the costs associated with the production of that RNG are recoverable through Fortis B.C.'s rates. so upgrading, injection, and the cost of acquiring the raw biogas itself.

MS. KLEIN: Is it through Fortis BC or Fortis, their affiliate, the alternative energy --

MR. McGILL: No, it's through the regulated entity, Fortis BC.

MS. KLEIN: Okay, and in Quebec?

MR. McGILL: Maybe, Mr. Chagani any could elaborate on the situation there.

MR. CHAGANI: We're not as familiar with the program in Quebec from a upgrading and injection perspective. We understand that there is a procurement of RNG program. But from an upgrading and injection perspective, we don't have the familiarity with that program.

There is -- there are plants actually in Quebec that are injecting directly into TransCanada as well. So we could -- like TransCanada has an injection program that we could provide a little bit more of an overview of.

MS. KLEIN: So maybe --

MR. MONDROW: Could I ask one question on that topic, if that would be convenient?

MS. KLEIN: Yes.

MR. MONDROW: Mr. Chagani, can you confirm that in Quebec, the Regis determined a number of years ago that upgrading services should not be operated within a regulated entity?

MR. CHAGANI: I'm not fully aware of that decision, so we could...

MR. MONDROW: No one on the panel is aware of what the regulator in Quebec has determined in respect of upgrading facilities? You haven't investigated that?

MR. STIERS: I think I can answer this sort of at a High level...

MR. MONDROW: Sorry, I first would like to know whether anyone in the business has investigated this.

MR. STEVENS: I was going to try and help you with that.

MR. MONDROW: Okay. Well, I mean, these folks are -- why -- VP --

MR. McGILL: As far as we know, the biogas upgrading assets would be a non-utility asset in Quebec.

MR. MONDROW: And the regulator has determined that must be the case in Quebec; is that not true?

MR. McGILL: I don't know if they've determined it must be the case, but that is the case, as I understand it today.

MR. MONDROW: The regulator has determined that upgrading facilities cannot be put in regulation; are you aware of that, Mr. McGill?

MR. McGILL: I'm aware that they are not in regulation. I don't know the Régie's decision word for word.

MR. MONDROW: Okay. So --

MR. STEVENS: The problem we've encountered, Ian, is the decisions we've found so far are in French and we have not had them translated, so while we've been able to have a little bit of discussion to try to understand at a high level what's happening, we don't know the details because we simply haven't seen the translated versions.

I believe that Mr. Chagani was starting in his conversations with Board Staff to offer that we could take this away and provide more details, but that's going to take us some time to find the English versions of things.

MR. MONDROW: Thanks.

MS. DeMARCO: Sorry, if I -- there we go. If I could just jump in here, because -- and jump to the chase, I'm going to ask for an undertaking to provide those decisions and the related programs across the country of Ontario, Quebec, and TCPL's related to RNG, so it might be time-saving if I just put that undertaking on the record right now.

So both the description of the programs and the associated regulatory decisions associated with those programs.

Would you provide that undertaking?

MR. McGILL: Yes, we can do that.

MS. KLEIN: And can we include the charges, if there's going to be charges, also too, on that undertaking?

MR. McGILL: We will look to see if there's monthly charges, and if we can find them we will provide them.

MR. MURRAY: That will be Undertaking JT1.1.

UNDERTAKING NO. JT1.1: TO PROVIDE THE DECISIONS AND THE RELATED PROGRAMS ACROSS THE COUNTRY INCLUDING ONTARIO, QUEBEC, AND TCPL'S RELATED TO RNG. ALSO TO PROVIDE MONTHLY CHARGES IF FOUND.

MS. KLEIN: Question 3.

MR. McGILL: Yes.

MS. KLEIN: Please provide the GHG reductions of a typical RNG project with EG outlining its assumptions. The GHG reductions are to be attributable to EGD's upgrading and injection service, not to the RNG, the biogas commodity.

MR. CHAGANI: So I think the question is a little bit unclear to me, but I can try and frame it and you can let me know if I'm on the right path here.

So when you mean the RNG, not the RNG commodity, you mean, like, the natural gas aspect, I believe, not the environmental attributes associated with the gas; is that correct?

MS. KLEIN: It's sort of linked to my question number 4. What I'm trying to get is the environmental attributes, yes, and --

MR. CHAGANI: So for a typical RNG, like a small-size plant that would take in, let's say, 500 million cubic metres of raw biogas per year as an input, the output, assuming about 50 percent methane in that raw biogas, would be 2.5 million cubic metres of gas per year.

The environmental -- or the tonnes of CO2 avoided would be 4.6 -- sorry, 4,600 tonnes equivalent that would be avoided, and that is based on the ON.400 emission factor of 0.001875 tonnes of CO_2 per M3 -- yeah, go ahead.

MS. KLEIN: Is that -- maybe you can with an undertaking show the calculations and this way we can all see them. Is that -- is the environmental attributes, though, connected with the supplier or is it connected to the upgrading and injection service? Because the upgrading service is you're cleaning the gas and the injection service is you're building a pipeline, so I'm trying to connect the GHG connected to your services versus to the actual -- the supplier of the biogas.

MR. McGILL: All right, so that's really the second part of this question. And the way to look at it is that the environmental attributes are associated with the RNG commodity that's produced, and that the upgrading and injection services that we're planning to offer facilitate the production of that RNG, so in our model any of the environmental attributes associated with that RNG that's produced would vest with the producer of the biogas.

So depending on what kind of carbon pricing regimes are in place, whatever carbon offset value is associated with that RNG, that would go along with the RNG, and our customer would be able to sell those environmental attributes, presumably, as well as sort of the pure gas commodity itself.

MS. KLEIN: Okay.

MR. McGILL: Does that help you or...

MS. KLEIN: Yes. So Staff understands it that the upgrading and injection services don't have sort of GHG reductions, like, no GHG reduction would be reduced in your -- let's say your compliance obligation in a cap-and-trade market, but the GHG reductions are connected to the commodity itself?

MR. McGILL: So under the current rules, I'll put it that way, to the extent that RNG is injected into our system, that would reduce on a one-for-one basis in terms of tonnes of carbon the allowance purchase requirement the company has under the cap-and-trade regulations today.

MS. KLEIN: But that assumes that you're buying the biogas? I'm kind of confused. Why would you --

MR. McGILL: No, because we don't even need to buy the biogas, so the way the GHG or the carbon emission reporting rules work is that the gas that comes into our system is measured at the gate stations. Based --

MS. KLEIN: Okay.

MR. McGILL: -- on that there is a conversion, the formula to convert that volume of natural gas into tonnes of carbon emissions, and that's what our allowance requirement is based on, but part of that determination is that any gas sourced from biomass you subtract from the carbon allowance requirement, so there's a one-for-one -- this is the way the rules are written today. So there is a one-for-one benefit just by injecting the gas into our system, and then wherever it goes to beyond that, there's further potential offset benefits that would initially accrue to the producer that they may be able to sell in the market for offsets, or RINs in the U.S., whatever.

MS. KLEIN: Can you -- we're doing an undertaking in terms of the GHG calculation. Can you put in the rules and include all of that together in that undertaking?

MR. McGILL: Yes, we can give you the references to the Ontario regulations with respect to GHG reporting.

MS. KLEIN: Okay --

MS. GIRVAN: Could I ask a question -- sorry, Steven. What rules are you talking about? Are these the rules underlying the cap-and-trade program?

MR. McGILL: I believe it is the GHG ON.400. It's the GHG reporting requirements, which is what our allowance purchase requirement is based on.

MS. GIRVAN: But that is tied to the cap-and-trade program. Yes, okay.

MR. McGILL: I tried to make that clear up front, that as of today that's the current rules.

MS. GIRVAN: Yeah, no, sorry, I was just -- when you talked about "rules" I wanted to be clear --

MR. McGILL: Yeah --

MS. GIRVAN: -- on what rules you are talking about.

MR. MURRAY: Just before we have any more questions, I just want to mark that undertaking -- sorry, as an undertaking, JT1.2, the GHG calculation and related information that would be provided.

UNDERTAKING NO. JT1.2: TO PROVIDE THE GHG CALCULATION AND RELATED INFORMATION, IN RELATION TO OEB STAFF TEHCNICAL QUESTION #3.

MR. McGILL: Just to clarify that, Julie, those rules and regulations were in place before cap-and-trade, and as part of our overall GHG reporting requirements, and that's the way they were reported, and then when cap-and-trade came in it translated into the determination of the allowance requirement.

MS. KLEIN: Lisa?

MS. DeMARCO: I'm happy to ask further questions on that when I go -- if you want to complete because I'm next, or whatever works best for you.

MS. KLEIN: I'm okay.

MS. DeMARCO: Just to clarify that last point, I believe you're talking about the regulatory requirements pursuant to Regulation 416.99 as amended?

MR. McGILL: I would have to check that, but you are probably correct.

MS. DeMARCO: And then the associated guidance document for quantification associated with greenhouse gases and allowances for regulated emitters; is that fair?

MR. McGILL: Yes. Are we ready for question 4?

MS. KLEIN: No, sorry.

MR. MONDROW: Is that a rhetorical question?

MS. KLEIN: No, actually we are going through question 4, and I'm going 4b. So if EGD is recovering any deficiencies from this program in its GHG-customer variance account, please explain how ratepayers are not funding this program.

MR. McGILL: I think we had an interrogatory response that explained that, and if you just give us a moment, we'll track that down.

But, you know, at a high level -- let me make sure I've got the right question here -- 4b, yes.

So over the term of the contract the sufficiencies that these investments generate will equal or exceed the deficiency amount. So on a net present value basis over the life of these contracts, customers stand to benefit financially through the fees that we charge for the service, or the rates we charge for the service.

And then in the case of the upgrading service, because of the significant capital cost allowance benefits through the income tax that are payable, the upgrading aspect of the service in sufficiency in the early years so that it isn't even deficiency situation. It is actually contributing to reduce rates in the early years, and then it trues-up over the life of the contract to provide a small net benefit to ratepayers overall.

MS. KLEIN: And would the RNG producer be considered a ratepayer?

MR. McGILL: Yes, we'd be charging them -- our proposal is to charge them an OEB-approved rate, so I would call them a ratepayer.

MS. KLEIN: So would they be getting sort of any of the -- anything in the deferral account, they would be paying for that, too, or the variance account?

MR. McGILL: They wouldn't be seeing that in the fee for the upgrading or injection service. But to the extent that they are a gas customer for other needs, they would be picking up part of that cost through the cost allocation process, or the clearing of the variance account and the cost allocation process through whatever rate schedule they were taking sort of basic service under from us.

MS. GIRVAN: Can I just interject? So they're a distribution customer?

MR. McGILL: Yes.

MS. GIRVAN: Under what rate class?

MR. McGILL: Well, we are proposing under rate classes 400 and 401.

MS. GIRVAN: Okay.

MR. QUINN: Laurie, if I may, that answer kind of confused me. Are you saying that variance account would only be cleared to customers in rate 400 or 401?

MR. McGILL: No.

MR. QUINN: So it's to all customers?

MR. McGILL: Yes.

MR. QUINN: Okay. So it's not only visited upon those who are participating in an RNG market? It's all customers are at risk for balances in the deferral account?

MR. McGILL: Well, we are asking all customers to -- assuming that there is a debit balance in the deferral account, we would be asking all customers to cover that debit balance.

We would also be returning the sufficiencies once the project reaches a point where the revenues exceed the revenue requirement for the project, and we return the sufficiencies.

So the way the model works, when you set a rate to achieve a PI of greater than 1.0 over the life of the asset on a discounted cash flow basis, you end up returning a sufficiency to the customers that actually makes rates lower overall over that complete period of time.

MR. QUINN: I have some more questions in that area, but I'll defer to later. But you said setting the PI at greater than 1.0.

MR. McGILL: Yes.

MR. QUINN: When you design the rate, what are you establishing that number to be?

MR. McGILL: Well, in the example we have in evidence, we've set the PI to be 1.1. And the reason we did that was because if you go back and go through EBO 188, the Board's feasibility guideline for gas system expansion, what it requires for our investment portfolios, both the rolling portfolio and the overall investment portfolio, is that we maintain a minimum PI of 1.0.

So what that means is that over the life of the assets, existing customers aren't subsidizing new customers. And then EBO 188 goes somewhat further and says that we should add a safety margin to that 1.0. Traditionally, that safety margin has been an extra 0.1, so we typically target to operate those portfolios to achieve profitability index figures or PIs of 1.1. So that's what we've used here in the example we have in evidence.

MR. RUBENSTEIN: If I could just clarify something?

When you talked about clearing the deferral account to customers --

MR. McGILL: Yes.

MR. RUBENSTEIN: -- you were talking about customers who are consuming natural gas, so not rate 400 -- I don't know if it's rate 400 that you are proposing for this or 401, not rate 400 and 401. Those customers will only pay for the life of the contract, the fee?

MR. McGILL: Yes.

MR. RUBENSTEIN: And so the comments about, meaning if I'm a landfill now so -- and a gas customer somewhere else in my -- I have a building...

MR. McGILL: Well, you are most likely a gas customer at the site where the RNG is produced, as well.

MR. RUBENSTEIN: Fair enough. But it's not with respect to 400 and 401. They are only paying the fixed fee.

MR. McGILL: Not the way our proposal is set right now. So it is their gas consumption under whatever gas distribution rate they would be taking service under, where they would see the clearing of the variance or deferral account coming back to them.

But what we've done in rates 400 and 401 is we've designed those such that we can have a set levelized charge throughout the life of the contract, and the main reason we need to do that is to give the producer some certainty around what their costs are going to be produce the gas -- or the RNG, rather.

And the reason that's important is because in order to get these investments off the ground, we believe that the producers are going to need to enter into long-term sales contracts for the RNG. So by giving them a set price for long period of time, they should be able to -- they should be able to do that, and have a reasonable expectation of recovering their investment and the part of the facility that they are financing over the life of their sales contracts whereby they are selling RNG to parties in the marketplace.

MS. KLEIN: Can I clarify then? So when they issue, the RNG producer is considered a ratepayer. If they're not a gas consumer, they wouldn't be considered a ratepayer?

MR. McGILL: No, I would consider them a ratepayer because, as I said earlier, we are proposing that rate 400 and rate 401 are Ontario Energy Board-approved rates, so I would consider them ratepayers. It is a different style of rate.

MS. KLEIN: Yes, but if they're not gas consumers, they -- the variance account wouldn't be recovered. They wouldn't be part of that recovery.

MR. McGILL: That's correct, they wouldn't see a clearing of the --

MS. KLEIN: Okay.

MR. McGILL: -- if they only took rate 400 and/or rate 401 services from us, then they wouldn't see any charges coming back to them from the clearing of that variance or deferral account.

MS. FRASER: Or any returns?
MS. GIRIDHAR: Or credits.
MR. McGILL: Yes, or the later sufficiencies typically in later years. So they are held neutral.
MS. KLEIN: Okay.
MR. McGILL: And bear in mind that the way the rate is set is such that overall, there will be a net sufficiency, so they're not participating in that benefit.
MS. KLEIN: Okay.
MR. McGILL: Okay?
MS. KLEIN: Question number 5a: Please explain what other support EGD is seeking.
MR. McGILL: So I think most of the people here are aware that we did have an RNG procurement process underway earlier this year, and that was premised on the belief that we were going to be supported with funding from the provincial government to the tune of $100 million that would be available to basically subsidize the cost of procuring RNG supplies.
Sometime, I guess it was late in April, we were advised by the province that that would be put on hold pending the outcome of the election that happened a couple of weeks ago, so that at that point in time we notified the respondents to our RFP that we were putting the RFP process on hold and that we would revisit it, you know, if and when we find an alternate way of funding the program.
But we still have a lot of potential RNG producers that are interested in investing in RNG production

facilities in terms of, you know, anaerobic digesters or building facilities associated with landfills or wastewater treatment plants. Most of those are municipal governments, so that there is still a demand for this kind of service in the marketplace today, even though that Green Energy Fund funding isn't available to support the utility's procurement of RNG at this point of time.

MS. KLEIN: So the fact that the -- there is no longer the RNG procurement model or it's been put on hold, that this hasn't impacted your RNG enabling program takeup?

MR. McGILL: No, we still are going ahead with the one customer that we have entered into agreements with to provide these services to them, and we're in discussions with one or two others today that also want to pursue this kind of model.

MS. KLEIN: So your estimate of up to 37 RNG production facilities operating by 2025, that hasn't been impacted at all, or...

MR. McGILL: I think it would be impacted. I think there might not be as many as quickly as there otherwise would have been. But there's still a large amount of interest in the market.

MS. GIRIDHAR: If I could just add to that? In my opening statement I did talk about federal regulations that are likely in the form of clean fuel standards, and should they pass, you know, we do believe that the interest in RNG will pick up again just to comply with those regulations.

MR. QUINN: May I, Laurie, follow up on that?

MS. KLEIN: Yes.
MR. QUINN: I appreciate, Ms. Giridhar, the explanation up front, but is there evidence about what the draft regulations are or anything on the record for us to have a sense of what may be impending and why Enbridge is of the view that this will pick up again?
MS. GIRIDHAR: So we are part of an industry stakeholder group that is participating in these federal discussions. I guess I just have to go back and find out if we are able to share the materials that the government has shared at these task-force meetings, so why don't I take that away.
MR. QUINN: I would appreciate that, and to be clear, I would be looking for what the government is saying. I understand the CGA may have its views, and as vested stakeholders in the process I would be interested in what the government is now saying and what may be coming at us that would underpin that renewed interest in RNG.
MS. GIRIDHAR: Yeah, so certainly subject to the federal governmental allowing us to provide the materials, we will --
MR. QUINN: Okay. Thank you very much.
MR. MURRAY: So we will mark that as an undertaking, JT1.3.
UNDERTAKING NO. JT1.3: TO PROVIDE INFORMATION ABOUT AND/OR COPIES OF DRAFT REGULATIONS IF AVAILABLE THAT OUTLINES THE REGULATIONS TO SUPPORT BIOGAS INJECTED IN ONTARIO TO BE USED BY COMPANIES IN WA; TO FILE PUBLIC

DOCUMENTS FOR COMMENT ON THE CLEAN FUEL STANDARD FROM CANADA AND THE PUBLIC COMMENTS ON THE DRAFT RENEWABLE FUEL STANDARD FROM ONTARIO, FILED ON THE RESPECTIVE RFS AND CFS PROGRAMS.

MS. DeMARCO: I just wonder if I could add to that undertaking. The government has produced public documents for comment on the Clean Fuel Standard, similar the Ontario government has produced public comments on Ontario's renewable fuel standard. Could you file both of those public documents that both the Government of Canada and the Government of Ontario have filed on the respective RFS and CFS programs?

MR. McGILL: Yes, we can do that.

MR. MURRAY: That will be same undertaking, JT1.3.

MS. KLEIN: 5c, please explain whether Enbridge Gas's affiliate, Gazifère, is considering procuring biogas in Ontario.

MR. McGILL: It is our understanding -- yeah, so it is our understanding that Gazifère was pursuing an RNG procurement model. It was very similar, if not the same, as what we were pursuing, and it is premised on some government support.

And the other aspect to that is that it wouldn't necessarily be limited to RNG supplies originating in Quebec, so Ontario production would qualify as a source of RNG under their program. So if there is RNG produced in Ontario, you know, they could enter into contracts to procure it for use in Quebec.

MS. KLEIN: So that's Gazifère and other companies in the cap-and-trade --
MR. McGILL: In Quebec, so --
MS. KLEIN: -- in Quebec.
MR. McGILL: -- so presumably GMI would be in the same position.
MS. KLEIN: Okay. Now, is that the same -- would California also qualify for that, that if Ontario is producing RNG, California companies, it would qualify?
MR. McGILL: It's my understanding that under the WCI --
MS. KLEIN: Yes.
MR. McGILL: -- that would be the case, so given the current state of affairs we're not certain how this is going to unwind --
MS. KLEIN: So if we're -- oh --
MR. McGILL: Excuse me.
[Witness panel confers]
MR. McGILL: Yeah, so just to be clear, the WCI participants can source RNG from anywhere in North America, and then it qualifies for -- as an offset to their allowance requirement or carbon allowance requirement --
MS. KLEIN: So anywhere in North America, so Ontario doesn't -- for whatever reason, Ontario is no longer part of the WCI. They -- so anywhere in North America WCI -- so California, Quebec can source RNG in Ontario?
MR. McGILL: Well, I think, yes, you know, subject to what happens around the WCI. The RNG can be sold anywhere

in North America, and then it's just a question of what the environmental attributes would be valued at in various jurisdictions, so --

MS. KLEIN: What rule is that?

MR. McGILL: Pardon me?

MS. KLEIN: What rule is that in the WCI? Where is that? Do you have the source for...

MR. CHAGANI: So my understanding of the program is that it's not a WCI program specifically, it is actually a U.S. EPA program. It's under the RIN, which is a renewable identification number, and there are certain participants that are required to purchase these renewable identification numbers, so there is a track for this RNG to be, I guess, piped into the U.S. down to the consumer that requires that, which will then produce a renewable identification number.

Now, the specific regulations and, I guess, the overall program, we -- or at least I don't have a full understanding of where it's all based out of. It is a U.S.-based program, but at a high level that's the gist of it.

MS. DeMARCO: I wonder if I could jump in with an undertaking here. Perhaps you are conflating the California Low Carbon Fuel Standard, the Federal EPA Renewable Fuel Standards, and I wonder if you could you undertake to provide with us a clear delineation of the associated valuation of all of the elements that -- of the renewable fuel requirements that you are working under, including the California Low Carbon Fuel Standard, the Federal EPA Associated Renewable Fuel Standard, and the Ontario Renewable Fuel Standard, and the Canadian Clean Fuel Standard?

MR. STEVENS: I'm sorry, I am a bit confused by the notion of all the standards you are working under. I mean, I assume these would be the standards that the producers would be working under. I mean, Enbridge isn't talking about being the producer or the owner of this RNG.

I'm just trying to fit it into the relief sought in this case.

MS. DeMARCO: Yes. I'd understood that, in fact, Enbridge is claiming ownership of the indirect greenhouse gas reductions and potential environmental attributes from transporting the fuel, whereas the biogas producer is claiming ownership of the direct emission reductions associated from that. But I could have that wrong.

MR. McGILL: No, our proposal is that the producer of the biogas would retain the rights to all the environmental attributes associated with the RNG that's produced, so that we wouldn't be taking a position in any of those potential offsets, or RINs, or whatever other vehicles come about.

MS. DeMARCO: Just so that I'm clear, you would in fact be taking a position in terms of the displacement emissions associated with what's at your gate and what you now have quantified as decreased allowances, but what could be quantified as voluntary emission reductions or other emission reductions in other programs.

MS. GIRIDHAR: Under the other GHG reporting rules that are in existence today, but obviously absent a cap-and-trade framework. I mean, we have to determine what value that is for us.

MS. DeMARCO: Just so I'm clear...

MS. GIRIDHAR: There is a reporting value to it, but at this point, there is no monetary value if cap-and-trade did not survive. I think that was the sense in which we said the environmental attributes go with the gas.

MR. McGILL: So even the value of those environmental attributes under cap-and-trade would still rest with the producer of the gas, the RNG in our model. They wouldn't necessarily come to Enbridge through the process of providing the enabling service.

MS. DeMARCO: So perhaps we're stepping -- tripping over the definition of environmental attributes. You've got the direct emission reductions associated with the non emission of biogas, right?

MR. McGILL: Right.

MS. DeMARCO: One class of environmental attributes. Those stay with the biogas producer; that's fair?

MR. McGILL: Yes.

MS. DeMARCO: And then you have displacement emissions. You don't have regular natural gas going on your pipeline, you have RNG going on your pipeline.

MR. McGILL: Yes.

MS. DeMARCO: And right now, those are quantifiable, valuable in the form of decreased allowances that you're required to purchase.

MR. McGILL: So that secondary benefit fit I would refer to as the substitution benefit which, through the existing reporting regulation, reduces our allowance purchase requirement.

So that benefit is coming to the utility and its customers, by virtue of the fact that it reduces the number of allowances or offsets we have to acquire and then subsequently recover the cost within rates.

MS. DeMARCO: So the substitution or displacement benefit remains yours, whether or not you are under Ontario cap-and-trade, a federal carbon tax, or otherwise, fair?

MR. McGILL: Yes.

MS. DeMARCO: And then there is a third classification of instruments that fall within your definition of environmental attributes, and those could be eligible instruments under other programs including lower carbon fuel standards; fair?

MR. McGILL: Potentially, yes, depending on how that legislation unfolds.

MS. DeMARCO: Ontario-related lower carbon fuel standards, the renewable fuel standards, Canadian clean fuel standards, U.S. EPA renewable fuel standards, and then California --

MR. McGILL: And then California.

MS. DeMARCO: -- low carbon fuel standard.

MR. McGILL: Yes.

MS. DeMARCO: So those environmental attributes are also to the account of the biogas producer?

MR. McGILL: Yes.

MS. DeMARCO: So three types of environmental attributes, two to their account, one to yours?

MS. GRICE: Yes.

MS. DeMARCO: Could you please undertake to provide that delineation, who gets what and how the calculations work?

MR. McGILL: We can attempt to do that, yes.

MR. MURRAY: That will be undertaking JT1.4.

UNDERTAKING NO. JT1.4: TO PROVIDE A DELINEATION OF ENVIRONMENTAL ATTRIBUTES, WHO GETS WHAT AND HOW THE CALCULATIONS WORK.

MS. KLEIN: I'm not too sure, Lisa, if that solves -- my question was: So any -- the RNG that is put in Enbridge's distribution system now can be bought anywhere in North America? Not just the U.S., it's North America.

MR. McGILL: Yes.

MS. KLEIN: So California, anywhere in North America, okay. I just want to confirm that.

MR. CHAGANI: So that is our understanding, but it has not been tested yet as there is no RNG production in Enbridge's region right now.

But our understanding is that any jurisdiction that requires RNG would be able to purchase it once it's injected into a natural gas distributor within North America.

MS. KLEIN: How would you test this? What would --

you would have to get a contract and see if it...

MR. McGILL: Well, it would be one -- it would be an Ontario RNG producer that would enter into a contract to sell their RNG, and the instruments perhaps that are associated with that RNG production.

My understanding is the way the rules work, particularly in the U.S., is that once the RNG is injected into a certified pipeline, then the environmental attributes in terms of RINs, offsets, et cetera, basically are separated from the gas and from that point on, the gas is just treated like any other volume of natural gas. But then these other instruments sort of take on a life of their own and have a value in various carbon markets.

MS. KLEIN: Okay. Question number 6.

MR. McGILL: Yes?

MS. KLEIN: A: Please explain whether the agreement with the City of Toronto includes Enbridge Gas procuring any of the biogas from the City of Toronto.

MR. McGILL: So this is an easy one. The answer is no.

MS. KLEIN: Okay. Do you know if the City of Toronto has signed any sort of contracts for its biogas, or...

MR. McGILL: No, and we wouldn't be privy to that information in any case. I think it's really up to the city what they decide to do with the RNG that is produced out of their facility.

MS. KLEIN: Right. Question number 7.

MR. McGILL: Yes.

MS. KLEIN: If the OEB approves Enbridge Gas' and Union Gas' Amalco application, please explain whether Enbridge Gas will start entering into discussions with municipalities in Union's current service territory for its RNG enabling program.

MR. McGILL: Well, I think we are awaiting the Board's decision in our two MAADs applications -- I guess there's four all together across the two organizations right now. That will have a bearing on how and to what extent integration does take place between the two entities and that's something that we'll have to address, you know, these programs, along with many others, in terms of how they are going to be delivered by that integrated entity and I think it is premature to try to speculate on exactly how that will unfold.

MS. KLEIN: Okay, thank you.

MS. ZHANG: Question 8: Please identify any precedents where Enbridge Gas used the EBO 188 guideline for the TCF analyses for rate-setting purposes. Specifically, please identify any precedents where revenues or service fees are the outputs from the analyses to achieve a PI greater than 1.0.

MR. McGILL: Yes. So I think the best example of that is our rate 125 bypass rate, where we basically follow the same process we're using under rate 400 and 401 to determine the rate for these RNG upgrading injection facilities.

So in terms of rate 125, that is exactly how we can do it. We determine the cost of the facilities. We determine the revenue requirement over the life of those facilities that's required to recover depreciation, return and tax and O&M costs associated with them, and that's what becomes the rate under rate 125.

MS. ZHANG: Just to clarify, are we talking about the demand charge or the volumetric charge?

MR. McGILL: It's the billing charge.

MR. QUINN: If I may, the billing charge, are you saying is it a monthly service fee that is rate 125 or is it a demand charge based upon a certain right to a certain amount of volume?

MS. GIRIDHAR: So for rate 125 we do have a rate that is derived as an outcome of a cost allocation process. For dedicated rate 125 customers served off a dedicated line, we have a bypass competitive calculation that uses this DCF process to set a billing contract demand, which then becomes the basis for rate 125's charges.

MR. QUINN: So billing contract demand which gives them a right to a certain volume on a daily basis or a monthly basis?

MS. GIRIDHAR: It's used -- the billing contract demand is used for the sole purposes of billing the customer, is my recollection, so I worked on it 15 years ago, so apologies, my memory is not great.

MR. QUINN: No problem, Malini. I am just, I'm trying to discern between a variable charge based on how much volume they are taking or it's just a, here's your bill every month, it is the same amount every month independent of volume.

MS. GIRVAN: It is a fixed rate. It's --

MR. QUINN: Fixed rate. So fixed rates, so it's more like a demand --

MS. GIRIDHAR: Correct, just like a --

MR. QUINN: Okay. Thank you.

MR. BUONAGURO: May I ask one follow-up question? Is it also based on a PI of 1.1?

MR. CHAGANI: It is based on a PI of 1.

MR. BUONAGURO: Thank you.

MS. ZHANG: Okay, (b), (b) describes a methodology where the service fees can be determined through -- on a present-value basis, the service fee can be determined to be equivalent to the revenue requirement.

Can you please discuss if Enbridge had considered this type of a methodology to assess service fees. If so, please explain why Enbridge Gas decided not to use this methodology. If not, why not?

MR. McGILL: So, like, our understanding of the methodology you've described in the question is that it is -- results in the same outcome as the regular PI calculation. It's just a different way of stating the same equation, so that -- you know, and that's what we've used in determining, in the example we have in evidence, what the monthly charges would be under rate 400 and 401 in this example.

So -- and again, we've, you know, we set the PI to

1.1, so it's basically just -- what you're proposing is just basically a reworking of the PI calculation that would end up with exactly the same result as what we have proposed.

MS. ZHANG: No, what is described here is, calculate the service fees based on the revenue requirement rather than based on the discounted cash flow. So say over the 20 years we can calculate the accumulated present value of the revenue requirement.

MR. McGILL: Yes.

MS. ZHANG: And then we can get a fixed -- still a fixed -- a constant monthly -- monthly service fees that can get the summation of the present value over the 20 years, which is equal to the revenue requirement.

MR. McGILL: But that's --

MS. ZHANG: So here we were not touching the cash flow, we were just looking at the revenue requirement over the term of the contract.

MR. McGILL: Okay. The way I understand what you are proposing is that the net present value of the revenue requirement is what becomes the numerator in the PI calculation. The denominator in the PI calculation is the net present value of the cost of providing that service, so that's the net present value of the capital asset, cost of capital, tax impacts, and O&M cost, so you have the net present value of the revenue stream divided by the net present value of the costs, and you set that revenue requirement as the numerator in order to achieve a PI of 1 or greater and the PI calculation, which is what we did to calculate the rates under Rate 400 and 401, so as far as I can make out, we're basically doing this the way you've proposed. It's just that the mathematics -- it's just the equation is turned around mathematically, but it just ends up in the same result.

MR. MONDROW: I don't understand that. If the request is to calculate a revenue requirement which is based by definition on cost --

MS. KLEIN: I can't hear you.

MR. MONDROW: -- return -- pardon?

MS. KLEIN: Trouble hearing you. I don't think that mic's working. Sorry.

MR. MONDROW: If the calculation is based on a revenue requirement, which is driven by definition by cost, why would you then have a denominator at all? Why wouldn't you calculate a revenue requirement based on the costs and simply levellize that, so divide by number of years?

MR. McGILL: Well, that's basically what we do, but we are following the methodology in EBO 188, so it sets out the PI calculation exactly, what goes into the numerator, what goes into the denominator. You calculate a PI, so if the PI turns out to be less than 1, then that customer addition in the typical sense would be subsidized by existing customers.

MR. MONDROW: I understand, but the numerator in that calculation is not a revenue requirement, it is a cash flow, right? Maybe you get to the same answer, but the process is actually a different process, and I think they're asking for that process.

MR. McGILL: Well, I think it's a distinction without a difference --

MR. MONDROW: Maybe.

MR. McGILL: -- in that it's the net -- what's in the numerator or the PI calculation is the net present value of the net revenue over the life of the --

MR. MONDROW: The net revenue, but not the revenue requirement; those are different concepts. They may be the same number, but they are different concepts.

MR. McGILL: Yes.

MR. MONDROW: And there is no denominator involved in that. You just take the revenue requirement and you divide it by the number -- well, I guess there is. It is the number of years.

MR. McGILL: Yeah.

MR. MURRAY: Perhaps it might be helpful -- would it be possible for Enbridge to give an undertaking to show -- like, I understand your position is at the end you get to the same number, but there's different calculations to get to that number, so could you do the calculation using discounted cash flows and beside it using revenue requirement so you can kind of show how you go through the calculation and the number you get to in the end?

MR. McGILL: Just give us a moment.

[Witness panel confers]

MR. CHAGANI: So to answer Lawren's question, we can undertake to do that, but I will bring your attention to Appendix 5 and Appendix 6, so Appendix 5 is the DCF calculation that you are referring to, okay?

Appendix 6 is actually the revenue-requirement calculation that seeks -- that achieves a PI of 1.1. So perhaps an addition to this revenue-requirement calculation showing the present value. So if we were to go to line 15 and line 17, if we were to take the present value of those two lines, what we would see is that one divided by the other would be 1.1.

In your example you are saying if the two could equal, which would result in 1 divided by the -- so 16 divided by -- sorry, 15 divided by 17 would be equal to 1, in our case it's 1.1, so we could undertake to show that present value calculation if that's helpful.

MR. MURRAY: Yes, that would be helpful. That will be Undertaking JT1.5.

UNDERTAKING NO. JT1.5: TO PLEASE PREPARE AN ANALYSIS THAT DERIVES THE LEGALIZED SERVICE FEE THAT IS EQUIVALENT TO THE REVENUE REQUIREMENT (APPENDIX 6, LINE 15) ON THE PRESENT VALUE BASIS OVER THE SERVICE LIFE OF THE ASSET.

MS. ZHANG: Can I clarify one more thing here? In Appendix 6 here you are saying that line 15 over line 17, in the way I described here, will get a PI 1.0, so my understanding is that Enbridge Gas -- what Enbridge Gas is proposing here is a methodology to set rates.

So even if we get a 1.1 here like in some other cases, the PI value depends on the capital spending and O&M spending, the PI value can be different.

So which means -- so, what I'm proposing here is to do a calculation to determine their service fees based on revenue requirement, then go back to do the TRC analysis and see if we can get a PI greater than 1 or not.

MR. CHAGANI: So the methodology that you are describing is the methodology that we undertook to calculate do the calculate line 17.

I just want to take a step back. I said 15 divided by 17 would equal 1.1. It is actually the opposite. Line 17, which is the service revenue over the 20-year term, if we were to take the present value of that divided by line 15, which is the revenue requirement -- sorry, the present value of the revenue requirement, that would equal 1.1.

The way that we have calculated line 17 is first determining what the present value of the revenue requirement is, line 15, and then goal seeking a set rate over the 20-year term that would give us a present value equal to 1 or greater.

So to answer your question, I think we're doing exactly what you've described.

Now, the one thing we want to add to that is that when you have a revenue requirement that's different than your revenue, on a year to year basis you will see a sufficiency and a deficiency. That's what we are trying to recover with the variance account.

But over that 20-year term, because the present value of the two of them will be equal, the sufficiencies will cancel out the deficiencies. And in this example, when it's greater than 1, the sufficiencies exceed the deficiencies over the life of the contract.

MR. MURRAY: Okay, thank you. Those are all the questions for OEB Staff. Next on the list is Ms. DeMarco.

EXAMINATION BY MS. DEMARCO:

MS. DeMARCO: Thanks very much. I'm going to try and be surgical about what Board Staff has very graciously let us interject in already, and try to streamline a bit.

Broadly, Ms. Giridhar, you spoke very basically to the impact of government's -- now the provincial changing government announcements on the RNG program. I wonder if you could specifically comment on the impact of that on your mandated to undertake the RNG program.

MS. GIRIDHAR: You know, I should remind us here that we first came to this Board with an RNG program in 2011, long before cap-and-trade came into existence. So we believe that despite the pronouncements of the incoming government on cap-and-trade, this new incoming government has not actually said that carbon emissions reductions is not important to them.

To the best of our understanding, they have actually talked about a $500 million fund for carbon emissions reductions.

So the focus on carbon emissions reductions remains and certainly Enbridge, quite apart from Enbridge Gas Distribution, operates in -- I can't remember how many states and how many provinces in both the U.S. and Canada, and we seek to work with the local -- the government policies in each of these jurisdictions.

In our view, emissions reductions continues to remain a focus. RNG is a means of achieving emissions reductions, and as we look at carbon pricing and regulations complementing each other in this space, we note that there are several regulations that we will continue to be subjected to, whether they emanate from the federal jurisdiction, we note that several municipalities have community energy plans. I'm told that 80 percent of our customers live in municipalities with community energy plans that specifically look to carbon reduction, or are targeting carbon reductions.

So for all of these reasons, our focus on RNG remains, despite the provincial government's views on carbon pricing.

MS. DeMARCO: Is it fair to say that commitment is from your C suite on down?

MS. GIRIDHAR: As I said, Enbridge does believe it has a responsibility to look at emissions reductions across all of its jurisdictions, and to respond to the various levels of government in how it designs its programs.

So I think it's fair to say that commitment exists all the way down.

MS. DeMARCO: Specifically in relation to the granularity of this application, many of your references refer to the associated avoided allowance costs, the associated regulatory regime, mandatory regulatory regime, and all of your financial statements associated with it.

I'm just going to try to name them all, but you'll forgive me if I've missed one.

It's Exhibit B, tab 1, schedule 1, appendix 5 on general economic feasibility, appendix 6 on the revenue and revenue requirement generally with the RNG service writ large, and then appendix 7, specific to the RNG injection, the economic feasibility, appendix 8 specific to the revenue and revenue requirement associated with the RNG injection services, and then finally your ultimate rate design, rate 400 and 401 changes, all in fact stem from some of the mandates; is that fair?

[Witness panel confers]

MR. McGILL: All of the exhibits you've referenced have been formulated through our adherence to the EBO 188 feasibility guideline, which has been around since 1998 or 1999. So it predates all of the carbon cap-and-trade, carbon pricing legislation that's been in place in Ontario.

So what we've done is we've tried to build this business model as a utility business model, using existing regulatory frameworks and guidelines that have been in -- some of them have been in place for many, many years.

So the way those exhibits were constructed and the way those figures are calculated are consistent with those pre-existing regulatory frameworks and guidelines, and would not be impacted at all by the government's legislation with respect to carbon pricing in Ontario.

MS. DeMARCO: So I'll get into the specifics of the statements. But generally, the mandate that you state, that is the impetus for this application is in part the Ontario cap-and-trade system; fair?

MR. McGILL: I think that was one of the underlying, driving considerations behind the RNG enabling model that we constructed. But it has been designed so that it will stand up and work with or without carbon pricing in Ontario, and that's what we're proposing to do.

There's parties that are interested in producing RNG and that -- you know, we feel it's an important and an appropriate part of the role of the gas utility to help them and facilitate that -- the production of that gas.

MS. GIRIDHAR: I'm just going to jump in here -- sorry, go ahead.

MS. FRASER: Wouldn't it be fair to say that the value of carbon reductions hasn't changed; the mechanism has -- may be changing depending on what the government actually does. But the value of reducing carbon to the environment has not changed; the pricing mechanism has changed?

MS. GIRIDHAR: I think what -- because our proposal stands on its own whether we have a provincially-mandated carbon pricing or not.

If you look at our customers that are wanting the service -- for example, municipalities -- they have goals around carbon reduction that they are trying to fill with this. We understand that there are other industrial customers, for whatever reason -- corporate social responsibility, or whatever. They may be operating in carbon jurisdictions elsewhere. For whatever reason, there is a demand for RNG from municipalities and other consumers of natural gas, whether or not a provincial carbon pricing regime exists, so to that extent I do agree with you.

And I do want to point out, you know, I mean, just as a leader of this team, I am very impressed with the innovative approach that the team has taken in terms of actually using all of the principles that already exist, the precedents that the Board has already established in its regulation of natural gas, in coming up with this proposal that we have here. So we are relying on EBO 188. We are relying on precedents where the Board has permitted a plain-vanilla utility offering to coexist with competitive offerings. We are using the way the Board has looked at cost allocation. So all of these principles are long-standing principles in the derivation of this proposal.

MS. DeMARCO: So maybe it is easier if we just jump right into the specific schedules to get to where I'd like to go to get a better understanding of it, but before we do that, fair to say that in the absence of an Ontario cap-and-trade program every indication right now is that there will be a federal back-stop tax; fair?

MR. McGILL: That's our understanding, that the federal government intends to implement some form of carbon-pricing regime next year.

MS. DeMARCO: And instead of decreased allowance purchases you will have decreased taxes if you pursue -- decreased carbon taxes if you pursue this program; is that fair?

MR. McGILL: I would say that's potentially, yes, depending on the specific requirements of the federal legislation and how it's going to work.

MS. DeMARCO: Perhaps we can turn to Exhibit B, tab 1, Schedule 1, Appendix 5, which is your RNG BMS economic feasibility. And I see a number of aspects of page 3 there where you go through the spreadsheet of how you come up with the associated NPV and PI and then the associated revenue requirement on the next schedule, which is Appendix 6.

And very specifically, you've got the rate base aspects that are coming to bear, in terms of the cost that you estimate it will require to provide the service; do I have that right?

MR. McGILL: Yes, well, the schedule sets out or determines the revenue requirement and then compares that to the forecast revenue in each year, and the netting of those two figures results in an annual revenue deficiency or sufficiency as the case may be from one year to the next.

MS. DeMARCO: Right. So you've got an associated rate base and then at line 10 is return on rate base; is that fair?

MR. McGILL: Yes.

MS. DeMARCO: And then line 11 is O&M, which is your cost of providing the services.

MR. McGILL: Yes.

MS. DeMARCO: Municipal taxes, depreciation, et cetera. What I'm not seeing here, and correct me if I'm wrong, is either O&M or other savings associated with decreased allowance purchases or decreased cost.

MR. McGILL: Okay, so what we've done here is we've used the EBO 188 feasibility calculations to determine what the revenues are we need in order to support the investment and the facility that's assumed in this example and achieve that profitability index of 1.1 in this example, so that there's no provision in EBO 188 to take into account other, call them ancillary benefits that might accrue to either the individual customer that's taking the service or ratepayers in general. So we didn't attempt to try to model in any sort of overall carbon abatement benefit into these calculations, because we're doing our dead-level best to adhere to the requirements of EBO 188.

MS. DeMARCO: But just to be clear, that value, the actual savings, the lack of expenditure, doesn't accrue to the customers generally, it's for you. You have to require -- you have to purchase fewer allowances or will have to pay less tax; is that fair?

MR. McGILL: Well, no, to the extent our allowance requirement is reduced through the injection of natural -- or RNG into the gas distribution system, that's a benefit that flows through to all of our ratepayers through the entire cap-and-trade mechanism, so we have an allowance requirement. We purchase the allowances on a forecast basis. The cost of those allowances are included in our gas distribution charge. The variances between the forecast cost of those allowances and the actual cost allowances over time are tracked in the customer GHG variance account and then periodically cleared through to rates to true-up from the forecast of the carbon allowance cost to the actual.

So to the extent that bringing these RNG facilities online reduces the allowance requirement, it reduces the number of allowances we have to purchase and it also reduces the amount -- or the cost of those allowances that we have to recover in rates.

So the entire benefit flows through to the general ratepayer population, not the company.

MS. DeMARCO: Okay, so fair to say the savings are not reflected in this calculation?

MR. McGILL: That's fair to say, yes.

MS. DeMARCO: And all customers appear to be benefiting from what the biogas producer is paying for; is that fair?

MR. McGILL: They would be benefiting to the extent RNG is injected into the gas distribution system.

MS. DeMARCO: I wonder if I can ask you to update these appendices, 5, 6, 7, 8 to reflect a line item showing at least a reasonable estimate of the range of savings?

MS. GIRIDHAR: What carbon -- based on a carbon price?

MS. DeMARCO: Avoided allowance purchases currently, as it currently stands, or avoided carbon tax at the announced price, the legislated -- now legislated price of $20 a tonne?

MR. McGILL: I think we can take that away and attempt to do that. Sitting here off the top of my head I'm not quite sure how we would introduce that into, you know, the feasibility model. But we could identify what those benefits would be based on the example we have in evidence, and then it would be a matter of determining how we introduce -- whether or not it is appropriate to introduce them into the feasibility calculation that is driving the rate we're setting. So -- and you would introduce lots of questions: Well, should that benefit go back to the RNG producer through a reduced fee for these service or should it flow through the GHG customer variance account and be for the benefit of all customers? We have to make certain assumptions around that kind of treatment --

MS. DeMARCO: So we'll get to the cost allocation portion later, but just, can we get the undertaking on the record that you'll undertake to provide these charts with the associated carbon abatement savings or reasonable estimate thereof, whether it be the Ontario allowance --

MR. McGILL: I will attempt to reflect that. I'm just not sure -- we can add it as a separate line item to the table.

MR. MURRAY: That will be Undertaking JT1.6.

UNDERTAKING NO. JT1.6: TO PROVIDE THE CHARTS WITH THE ASSOCIATED CARBON ABATEMENT SAVINGS OR REASONABLE

ESTIMATE THEREOF.

MR. YAUCH: Can I ask a question about the undertaking before you move on, sorry, Lisa? Each reduction -- tonne of reduction of carbon as a result of renewable natural gas, according to your other proceeding, is significantly higher than the cost of just a carbon credit, correct? It was in the hundreds of dollars per each tonne reduced?

MR. McGILL: You are referring to the cap-and-trade compliance plan proceeding?

MR. YAUCH: Yeah. Yes, so if you do this undertaking, do you factor that in that each unit of gas, renewable natural gas, is actually a really expensive way to reduce carbon?

MR. McGILL: Well, based on the way our reporting requirements work, I don't think there is a cost to the utility of injecting RNG into the system.

MR. YAUCH: Assuming you get the full subsidy from the government to make up the difference, right?

MR. McGILL: No, but because it is a one-for-one reduction in the number of allowances we have to buy, so there is a benefit to the ratepayer as a result of that with basically no cost to the utility. So it's --

MR. RUBENSTEIN: Can I clarify something and -- working on the assumption that you do not procure RNG in your gas supply through a contract --

MR. McGILL: Yes.

MR. RUBENSTEIN: -- but someone else somewhere else does.

MR. McGILL: Yes.

MR. RUBENSTEIN: But the cap-and-trade program still exists -- let's work under the current framework. Do I understand that just because -- there's a contract and someone -- the fact that it's still just being injected into your system, you gain essentially the gas supply.

MR. McGILL: Our customers derive the benefit.

MR. RUBENSTEIN: But at the same time, the environmental attributes remain with the producer to then sell through an offset, or some other mechanism?

MR. McGILL: That's correct.

MR. MONDROW: And is that benefit only if the gas is consumed in Ontario?

MR. McGILL: That's not my understanding.

MR. MONDROW: So if the gas goes into your system and ends up in California, you still have a reduced allowance?

MR. McGILL: That's my understanding as to the way the GHG reporting requirements work, and the way our allowance purchase requirements work because they are based on the GHG reporting.

MS. DeMARCO: So can we just walk through this again, because I think the clarification of what you're calling environmental attributes helps get through some of these challenges.

We have the direct emission reduction from the biogas producer. They are not emitting that methane which has a global warming potential of 25 times that of CO2. Is that the source?

MR. McGILL: Twenty-two times, but...
MS. DeMARCO: I believe it's 25 times, subject to check, with the most recent IPCC reports; is that fair?
MR. McGILL: It's on that order of magnitude, yes, in terms of methane destruction.
MS. DeMARCO: And then the second source of emissions reductions is the displacement, or what you are calling substitution environmental attributes. That is you don't have regular -- I had to go dig in the ground to get it natural gas produced by some natural gas producer in Alberta coming onto your system. You have captured renewable natural gas coming onto your system and that is the displacement emissions reduction or -- substitution emission reduction, in your terminology.
MR. McGILL: Yes.
MS. DeMARCO: And then there is a third type of environmental value, which we are lumping into that category of an environmental attribute. And that's not based on the quantified GHG reductions, but more based on programs that exist for low carbon fuels. Is that right?
MR. McGILL: Those programs give rise to instruments in the form of offsets, or RINs in the United States, that have...
MS. DeMARCO: I want to be really clear on this point. A RIN is not an offset, correct?
MR. McGILL: Correct.
MS. DeMARCO: A RIN is a regulatory program benefit that is a function of a government allocation for renewable

natural gas; fair?

MR. McGILL: Yes. I guess what I'm trying to say is it results in an instrument that can be traded in the market for some value. But it's not the same as an offset.

MS. DeMARCO: A RIN doesn't have a GHG quantification associated with it. It is an instrument allocated per unit of gas injection, fair?

MR. McGILL: Yes.

MS. DeMARCO: So all of those things you are calling environmental attributes here?

MR. McGILL: Yes.

MS. DeMARCO: Okay. So what we're talking about is not per se double counting of GHG reductions. It's qualifying for whatever program value you can?

MR. McGILL: Yes.

MS. DeMARCO: Okay. So we have that undertaking from you to go through and delineate the GHG emission reductions and the associated values, and the programs, and the quantification of each?

MR. McGILL: Yes.

MS. DeMARCO: Thank you. You have at page 13, B1.1, table 1, a general quantification of customer and system GHG abatement from RNG.

MR. McGILL: Yes, we have the table.

MS. DeMARCO: So just -- now that we've got the clarification of the forms of environmental attributes, what do these quantification figures reflect? Direct, substitution, or RIN?

MR. McGILL: Give us a moment.

MR. MONDROW: Lisa, are you talking about this table that's on the screen that has cubic metres?

MS. DeMARCO: Yes.

MR. McGILL: So the exhibit you're referring to, or the table in the exhibit that you are referring to only sets out potential volumes of RNG. It does not quantify the associated GHG benefits.

MS. DeMARCO: So this table is translatable only to the direct emissions and potential emission reductions from the biogas producer?

MR. McGILL: Well, I think -- yes, in terms of a substitution value, that is correct. But the volumes themselves would give rise to whatever additional carbon reduction value is associated with the gas.

MS. DeMARCO: So this doesn't reflect your substitution value; this reflects what's going on at the level of the biogas producer?

MR. McGILL: Well, all this table is doing is setting out what the potential RNG volumes are from different sources of biogas feed stock.

MS. DeMARCO: Let's translate that into potential greenhouse gas reductions. If this is Canada's potential biogas production...

MR. McGILL: This is Ontario.

MS. DeMARCO: There's both, right? Canada and Ontario.

MR. McGILL: Yes.

MS. DeMARCO: The potential greenhouse gas reduction directly from those biogas producers is what, if you translated those numbers into greenhouse gas reductions?

MR. McGILL: I'm not sure if we have that in evidence or not.

MS. DeMARCO: I don't think you do. Would you undertake to provide it?

MR. McGILL: Yes, we can.

MS. DeMARCO: So that's the direct emission reductions. Let's go to the substitution.

MR. MURRAY: Before we go on, perhaps I can just take the undertaking, JT1.7.

MR. McGILL: Just to be clear, in terms of trying to associate GHG reduction values with these volumes of RNG, we are going to need to make some assumptions just around how much methane is being destroyed from each of those different feed stocks.

So in the case of landfill gas, if the methane is already being flared, the GHG reduction value is less, et cetera. So we will need to --

MS. DeMARCO: If you could just put your assumptions in the calculation, that would be great, regarding the methane -- additional methane destroyed, number one.

Number two, the global warming potential you are using.

MR. McGILL: Yes.

MS. DeMARCO: And if you need to use a range...

MR. McGILL: Yes, okay.

MS. DeMARCO: So we are just going to modify the undertaking to reflect that, if we can.

So getting back to the initial point, this is the direct emission reductions, the substitution value. Could you undertake to quantify the emission reductions, or the decreased emission reporting associated with the potential substitution value, if you captured this?

MR. McGILL: Yes, we can do that.

MS. DeMARCO: And third, could you attempt to quantify the potential RIN or other environmental attributes associated with what you are allowing to be injected?

MR. McGILL: In terms of tonnes of carbon, or...

MS. DeMARCO: In terms of RINs or other environmental instruments that have value.

MS. GIRIDHAR: I assume a treated value?

MR. McGILL: We can undertake to attempt to do that, yes.

MS. DeMARCO: Thank you. I appreciate that it's a difficult task, but I think it is viable valuable to everybody understanding what's going on here, and the Board understanding the real value of this program.

MR. MURRAY: I think it makes sense to put all three of those matters under the same undertaking, JT1.1.

UNDERTAKING NO. JT1.7: (1) TO PROVIDE THE POTENTIAL GREENHOUSE GAS REDUCTIONS DIRECTLY FROM BIOGAS PRODUCERS; (2) TO QUANTIFY THE EMISSION REDUCTIONS, OR THE DECREASED EMISSION REPORTING ASSOCIATED WITH THE POTENTIAL SUBSTITUTION VALUE, IF YOU CAPTURED THIS;

(3) TO ATTEMPT TO QUANTIFY THE POTENTIAL RIN OR OTHER ENVIRONMENTAL ATTRIBUTES ASSOCIATED WITH WHAT YOU ARE ALLOWING TO BE INJECTED, IN TERMS OF RINS OR OTHER ENVIRONMENTAL INSTRUMENTS THAT HAVE VALUE.

MS. DeMARCO: I was just going to ask -- I was going to ask about -- you've undertaken already to provide the regulatory decisions and description of all other RNG programs in Canada.

Secondly, my question is: In relation to the separation of the two aspects of the RNG service, as I understand it -- correct me if I'm wrong -- the upgrading service effectively you deemed as a competitive service, i.e. you're not obliged to go to Enbridge to upgrade, is that right?

MR. McGILL: We are offering upgrading as an optional service. As I think I indicated earlier, I don't believe that there's anyone offering something comparable to what we're proposing at this point in time.

There's equipment providers and contractors that install the equipment, but I don't know of anyone that's considering offering it is sort of a package service, as we are proposing to do.

MS. DeMARCO: But theoretically, someone else could upgrade and just take the injection service?

MR. McGILL: Yes.

MS. DeMARCO: And how theoretical is that? Is that a practical reality?

MR. McGILL: Oh, it's a practical reality, yes.

MS. DeMARCO: It is; okay, great.

And then the second part of the service, the injection service, is effectively a monopoly service; you are not providing others access to the pipeline to --

MR. McGILL: Well, our position is that it's our responsibility to inject natural gas RNG, perhaps hydrogen in the future, into our system, and that that's part of our role in ensuring the reliability, integrity, and safety of the system, so that we see that as a pure utility function.

MS. DeMARCO: I understand that's your position in terms of that being a pure utility function. Can you provide any analysis that you've undertaken to determine what is effectively competitive service for the upgrading and what is a monopoly service for the injection?

MR. McGILL: In terms of the upgrading or the injection?

MS. DeMARCO: So as I understand it you determine the upgrading is a competitive service, the injection is not, it's a monopoly service, and --

MR. McGILL: Okay, so the point I'm trying to make is that as far as we know there is no one offering the same kind of upgrading service that we are, so to characterize it as competitive, I guess potentially it could be. The way I'm characterizing it is it's an optional service, so if someone wants to do the upgrading themselves, as long as they can upgrade the gas to meet the pipeline standard that we have set, then we will inject that gas into our system for them. But I, you know, hesitate to characterize it as a competitive service right now because, as far as I know, there is no competitors.

MS. DeMARCO: I'm happy to soften my language. A non-obligatory service; fair to say?

MR. McGILL: Yes.

MS. DeMARCO: Would you undertake to provide your analysis that went into determining that the upgrading service was a non-obligatory service but the injection is mandatory?

MR. McGILL: Yes, we can do that.

MS. DeMARCO: Thank you.

MR. MURRAY: That will be Undertaking JT1.8.

UNDERTAKING NO. JT1.8: TO PROVIDE THE ANALYSIS THAT WENT INTO DETERMINING THAT THE UPGRADING SERVICE WAS A NON-OBLIGATORY SERVICE BUT THE INJECTION IS MANDATORY.

MS. DeMARCO: We've gotten through the financial analysis piece. There are a few elements that I'd like to talk to you about in relation to other drivers to facilitate RNG, and can I ask you to comment -- with the business case -- or are you feeling any pressures to continue with the business case for RNG from, for example, the task force for carbon-related financial disclosures?

MR. McGILL: Not that I'm aware of, no.

MS. DeMARCO: Would you agree that the TCFD is calling for enhanced carbon-related disclosure, so for all public reporting issuers?

MR. McGILL: I'm sorry, I don't think we can answer these questions. We just don't have knowledge of what that task force is doing.

MS. DeMARCO: Let me ask: Have you ever had a shareholder resolution relating to your greenhouse gas position?

MR. McGILL: I don't know.

MS. DeMARCO: Would you undertake to determine that?

MR. McGILL: Yes, we can undertake to look for that.

MS. DeMARCO: Thank you.

MR. MURRAY: That will be Undertaking JT1.9.

UNDERTAKING NO. JT1.9: TO ADVISE WHETHER ENBRIDGE HAVE EVER HAD A SHAREHOLDER RESOLUTION RELATING TO ITS GREENHOUSE GAS POSITION.

MS. DeMARCO: Can I ask you also, looking at the potential corporate-wide emission reductions that we just arrived at from two undertakings ago, can you put that in the context of your corporate-wide emissions, how significant it is to the corporate-wide greenhouse gas emissions?

MR. McGILL: Yes, I think we can undertake again to attempt to do that, yes.

MS. DeMARCO: Thank you. And if we can mark that?

MR. MURRAY: That will be Undertaking JT1.10.

UNDERTAKING NO. JT1.10: RE: THE POTENTIAL CORPORATE-WIDE EMISSION REDUCTIONS FROM UNDERTAKING JT1.9, TO PUT THAT IN THE CONTEXT OF THEIR CORPORATE-WIDE EMISSIONS; HOW SIGNIFICANT IT IS TO THE CORPORATE-WIDE GREENHOUSE GAS EMISSIONS.

MS. DeMARCO: I am very cognizant that I am well over my time and my last series of questions are very specific to Indigenous populations and specifically what you propose to do.

As I understand it, starting at B1-1, paragraph 32 at page 11, 37 facilities estimated by 2025 on farms, wastewater treatment plants, food processing plants, and landfills; do I have that right?

MR. McGILL: Yes.

MS. DeMARCO: Do you have a map of the proposed locations?

MR. McGILL: We can undertake to determine if we have a map of those potential locations. Off the top of my head I don't know if we do or not.

MS. DeMARCO: Okay, and it would be fabulous if you could provide a map if you've got it of those proposed locations.

MR. MURRAY: That will be Undertaking JT1.11.

UNDERTAKING NO. JT1.11: TO PROVIDE A MAP OF THE PROPOSED LOCATIONS REFERRED TO AT EXHIBIT B1.1, PAGE 11, PARAGRAPH 32; TO PROVIDE A SECOND MAP OVERLAYING THE FIRST NATIONS AND INDIGENOUS COMMUNITIES IN THOSE SAME AREAS, FOR THE UPGRADING SERVICES AND THE INJECTION SITES.

MS. DeMARCO: And so just so that I'm clear on that, it is for both parts of the service for the upgrading services and for the injection sites.

MR. McGILL: Well, yes, I guess the potential exists for either both services or just the injection services at

any of those locations, yes.
MS. DeMARCO: So whatever you've got in terms of map would be very helpful.
MR. McGILL: Yes, we will check to see what we've got and provide what we have.
MS. DeMARCO: And I wonder if you could provide a second map overlaying the First Nations and indigenous communities in those same areas?
MR. McGILL: We can undertake to, again, attempt to do that.
MS. DeMARCO: So let's mark that as an undertaking.
MR. MURRAY: Why don't we include that as the same undertaking, JT1.11.
MS. DeMARCO: Thank you. I'm assuming, but I'm not sure if I'm correct in this assumption, that the injection services will be in and around the existing Enbridge pipeline and the easements that it's located on?
MR. McGILL: Well, the closer the RNG production facility is to our existing gas distribution system, the less costly the project will be, so -- and so distance from the existing facility has an impact on feasibility of these projects.
MS. DeMARCO: So just so that I'm clear on that point, injection isn't directly into your pipeline? You might have to build a little something to inject into?
MR. McGILL: Yes. So if the RNG production site was, let's say 20 kilometres away from our existing system, we'd have to build a 20-kilometre pipeline to connect the

injection facility to the gas distribution facility. So the cost of that pipeline would be attributable to the project and be part of the cost consideration that's included in the feasibility testing of the project, and what you would find is the way we would set the rates for that, because that pipeline connection would be included as part of the injection facility cost. It's just that the monthly fee would be that much higher. So let's say compared to a facility that was only one kilometre away from the existing system. It's like community expansion, but reversed.

MS. DeMARCO: So will there be related LTC applications or are they all exempt?

MR. McGILL: I believe that most of these will probably result in LTC applications.

MS. DeMARCO: Do you have an estimate of how many LTC applications we're looking at?

MR. McGILL: No.

MS. DeMARCO: So I was wrong in that assumption, so I guess we've got the map of approximately where they are.

MR. McGILL: Yes.

MS. DeMARCO: So that will be very helpful.

I have a couple of follow-up questions from the discussions to date, if you would just bear with me a second.

Ms. Giridhar, you spoke to on or before August 31st, 2018 updating the GES evidence. I wonder if you could undertake to, as applicable, update the RNG evidence as well?

MR. McGILL: Well, to the extent we believe we need to update the RNG evidence we will. What we said in the letter is we would report back to the Board with respect to the geothermal energy service evidence by August 31st. I don't know if that would include updated evidence by that time, but we would provide an update as to how we had progressed to that point in time, which may or may not include revised evidence.

MS. DeMARCO: That's in relation to the GES, as I understand it.

MR. McGILL: Yes.

MS. DeMARCO: I'm asking specifically should -- and I'm happy to take it that no updates are required -- but should updates be required to the RNG portion would you undertake to update the RNG evidence as well?

MR. McGILL: Yes, if we need to, we will.

MS. DeMARCO: Can we get an undertaking on that?

MR. STEVENS: I'm not sure that's actually -- I'm not sure, Lisa, that's something we would actually answer as an undertaking. I think the answer that the panel has given is, should Enbridge determine it needs to update its application, it will do so.

I think everybody can take Enbridge's answer to be that, if there's no update, that Enbridge has determined that it's not necessary, but I don't think this is something that we would answer along with the bundle of undertakings that are otherwise being provided today.

MS. DeMARCO: I'm not going to stand on form over function. I'm happy to leave it as such.

My last series of questions relate to the nature of the charge. It's, as I understand it, a flat fee.

MR. McGILL: Yes.

MS. DeMARCO: For both services.

MR. McGILL: Yes.

MS. DeMARCO: It is not a volumetric charge.

MR. McGILL: That's correct.

MS. DeMARCO: And so theoretically, if they're hoping to inject a hundred metres cubed of RNG, they would pay the same flat fee?

MR. McGILL: That's right.

MS. DeMARCO: So pragmatically, what's the threshold size of RNG producer that you think will take the service?

MR. McGILL: Again, I think that depends on the nature of the feed stock, the location of the facility in relation to our existing facilities, you know, costs that are specific to the construction of the facility itself depending on the nature of the site, the ground conditions. It's going to vary from one instance to another.

MS. DeMARCO: So as I understand it, you've got about a $60,000 flat fee for the injection service, and 107,000 for the upgrade service.

MR. McGILL: In this example.

MS. DeMARCO: Okay. And you have four types of biogas-producing entities, is that right?

MR. McGILL: Well, at a high level, four sources of biogas as a feed stock.

MS. DeMARCO: Can I ask you to undertake to estimate a threshold for each of those four types of feed stock sources that would take, or be able to pay 60,000 or 107,000?

MR. McGILL: So the monthly fees, the 60 or the 107,000 in the example we have, is driven by the cost of the specific facility.

So if we had another example with a facility that was half the size, half the cost, it wouldn't exactly be one-to-one, but I would expect the fees to be about 50 percent.

So the fee is scalable based on the capital -- largely the capital cost of the facility. I don't think the operating cost would change much from one facility to the next.

MS. DeMARCO: Do you have a minimum level of fee that you are willing to charge?

MR. McGILL: No.

MS. DeMARCO: So theoretically, your fees could be as low as $100 for injection.

MR. McGILL: Theoretically, yes. Whether that would be practical or not is a...

MS. DeMARCO: That's what I'm trying to get at here, what's the practical reality of the scope and scale of these services that you're providing.

Perhaps you could undertake to provide some semblance of an understanding of what the bookends of the scope and scale of the services will be?

MR. McGILL: We could take a look at that. But again, it's going to depend both on our side of the equation and the biogas producer side of the equation, So, you know, what we would do is we would investigate a potential producer site. We would determine the cost of the facilities and the cost of connecting the facilities to our existing system.

We would work out what the monthly rates would be for each of the upgrading and the injection service. We would go back to them, and then it would really be that biogas producer's decision as to whether or not their project was feasible based on those costs.

So it's really hard for us to try and pin down what sort of the minimum practical size would be, because it would largely be dependent on assumptions that the biogas producer is making around what the value of their end product is going to be, and we don't know that.

MS. DeMARCO: I'm happy and very much appreciate the precision challenges that you might have in doing this, and the assumptions that you might bring to bear.

But some semblance -- if you could undertake to provide some semblance of the scope where you, who are grounded in the practical realities of what gas customers, including biogas customers would accept, can give us a sense of what the bookends of this program are.

MS. GIRIDHAR: I think it's really hard to come up with the bookends, because we don't know what the value of that end product is for the customer.

So I think this would be almost impossible for us to determine what those bookends would be.

MS. DeMARCO: Perhaps if we go with an estimate of the federal tax value at $50 a tonne? Would that help as an assumption?

[Witness panel confers]

MS. GIRIDHAR: So trying to be responsive to this request, what we could do is to ask the sort of the engineering experts in our company what is the smallest size injection station that we could put in and, you know, what might that cost, and then assume that the RNG producer is right there and, you know, we he have just the minimum amount of pipe and so on, and I think that could end up becoming sort of one end of the bookmark. But it would be very hard to do anything about beyond that.

MS. DeMARCO: I think that is very helpful and at least indicative directionally. So could we have an undertaking in relation to that?

MR. MURRAY: That would be undertaking JT1.12.

UNDERTAKING NO. JT1.12: TO ASK ENGINEERING EXPERTS ABOUT THE SMALLEST SIZE INJECTION STATION THEY COULD PUT IN, AND ESTIMATE A COST, ASSUMING THE RNG PRODUCER IS RIGHT THERE AND ASSUMING A MINIMUM AMOUNT OF PIPE

MS. DeMARCO: Those are my questions, with apologies for the overtime.

MR. BUONAGURO: Could I just ask a clarifying question on that last undertaking?

Would that include an analysis of what kind of flow that allows? I'm assuming you may have already been thinking about doing that.

MS. GIRIDHAR: Yes, there would be an implicit assumption for the smallest station, in terms of what the flow of gas might be.

MR. QUINN: If I may just follow that up, though, one of the assumptions said the customer is right there. Is the cost of the pipeline, to the extent there is a pipeline, is that going to be recovered in the mandatory service, the injection service?

So again, the scope of what Lisa was talking about, if somebody is 20 kilometres away, obviously it's a lot bigger cost, and they have to do their own economics of whether that made business sense to them.

MS. GIRIDHAR: Correct. You know, there's another factor, which is are we able to accept RNG in at that location, because our ability to accept RNG at a location as a function of what the rest of the demand is on that location.

So that's why it becomes such a complicated thing to, to do any kind of high-level analysis on it.

MR. QUINN: Okay, thank you.

MS. GIRIDHAR: We would have to be very specific about what that bookend is.

MR. MURRAY: I think now is a good time for the morning break, and we'll come back for 11:45.

MS. DeMARCO: Just before we do that, I want to make sure that we got that undertaking marked and we're good.

MR. MURRAY: I believe it was JT1.12.
MS. DeMARCO: Okay, good, thanks.
--- Recess taken at 11:33 a.m.
--- On resuming at 11:57 a.m.
MR. MURRAY: Next on the list of questioners is Mr. Vellone for APPrO.

EXAMINATION BY MR. VELLONE:

MR. VELLONE: Thank you very much. Good morning, panel. I'd like to start with a follow-up on Staff's Technical Conference Question number 1. Maybe we could throw that up on the screen.
So you will remember from this morning OEB Staff asked why Enbridge is doing its upgrading service in the -- proposing to do it in the regulated utility as opposed to an unregulated affiliate; do you recall that conversation?
MR. McGILL: Yes, I do.
MR. VELLONE: And I just want to make sure I got your answer correct, make sure I understood it correct, so I'm going to repeat it back to you and see if I got it down.
My understanding is that an advantage of doing it in the regulated business is that it would benefit from a lower cost of capital than doing it in one of your unregulated affiliates. Is that a fair understanding of what you said?
MR. McGILL: Yes, what I said was that in other parts of our business a project like these -- or projects like these would have to compete for capital against other projects or business opportunities, and that would be

likely to result in a higher cost of capital.

MR. VELLONE: Okay, and my understanding -- another reason why you're saying this should be done in the regulated business is because Enbridge can take -- is in a position where it can take advantage of certain tax benefits associated with these facilities, such as accelerated CCA and things like that; is that correct?

MR. McGILL: Yes, that's correct.

MR. VELLONE: Did I miss anything else? Were those the primary reasons why you are suggesting to do it in the regulated utility?

MR. McGILL: Well, I think some of the other reasons are articulated in our response to Energy Probe question number 2, and I think beyond that the upgrading service fits within the definition of a gas distribution service under the Ontario Energy Board Act.

MR. VELLONE: Why don't we pull Energy Probe number 2 up just so I can see what you are referring to here.

Okay. And so this is referencing, effectively, the argument that it does fit in the scope of the Ontario Energy Board Act; is that my fair understanding?

MR. McGILL: Yes.

MR. VELLONE: Okay. Are there any other reasons that you'd want to put on the record just while we are trying to create an exhaustive list here?

[Witness panel confers]

MR. McGILL: No, I don't have anything to add at this point in time.

MR. VELLONE: Okay, let's park the legal argument for a minute, the stuff in Energy Probe number 2, and deal with the more business-oriented arguments, the lower cost of capital, the ability to take advantage of tax advantages.

MR. McGILL: Yes.

MR. VELLONE: Is there anything unique to RNG upgrading that makes it compelling for the regulated business to do those activities with just those two reasons? Or would those same two reasons be a reason for you to get into other ventures, geothermal, natural gas generation for electricity, other competitive ventures? Is there anything unique to RNG?

MR. McGILL: I think the aspect of RNG that is or was unique in that was that it would bring an overall benefit to our ratepayers through a reduction in our carbon allowance purchase requirements, so I think that would be different than some of those other examples that you've referenced.

MR. VELLONE: But would you get those benefits if you undertook the same activity in an unregulated affiliate, I guess is the question. I'm trying to contrast where it's done.

MS. GIRIDHAR: You know, I think with respect to your broader question -- that is, what is unique to RNG versus other activities -- I just do want to call out the market transformation capability that we have within regulation, so intrinsically what regulation allows us to do is to spread costs out over a longer duration of time. It allows us to use the utility's ability to deploy solutions cost-effectively, build scale, and, you know, these reasons, I think, can be applied to a number of clean technology solutions, and just a reminder, you know, Ontario largely moved to high-efficiency furnaces from mid-efficiency furnaces because of the utilities' participation in that space through its DSM programming, and we've had other examples in the past, so I think the market transformation capability arises from utility regulation, and that's what we'd like to leverage in this case.

MR. VELLONE: Okay. I'm going to try to follow along with that. So when you are saying market transformation you're really talking about -- is it a chicken-and-egg problem here? RNG is not necessarily economic to upgrade on its own, but if the utility invests in these upgrade facilities you can help bring it along? Is that what you are saying market transformation is?

MS. GIRIDHAR: Yes, so there are several barriers that prevent solutions from becoming commonplace or, you know, deployed. Some of them are cost barriers. Some of them could just be barriers with respect to, you know, how it gets done. I mean, as an example, you know, the application of codes and standards and having the right framework within which to deploy solutions, I mean, I think we have an ability to do all of that within regulation.

MR. VELLONE: Would RNG upgrading services be economic in the absence of a regulated service offering at this time, if you were to do it in your competitive affiliate, for example?

MS. GIRIDHAR: I think it depends. To the extent that we are able to offer a service, a levellized service, at a lower cost of capital, we are obviously reducing the cost of upgrading service relative to doing it in an affiliate.

Now, obviously if price was no barrier for the RNG producer they could pay higher rates and then be able to still produce RNG, but we know that that's not the case because there isn't any RNG produced in Ontario right now, so I think we would believe that it does lead to more participation in the space as a result of it being a regulated service, and that's why we call it an RNG enabling service.

MR. VELLONE: Just to clarify that point, my understanding -- and this is in reference to CBA Interrogatory No. 2 -- is that there is a facility in Ontario that is producing RNG that is of high enough quality that you could inject it into your system if you had the injection facilities available.

MR. McGILL: There is one facility that is owned by the City of Hamilton that injects quantities of pipeline-quality RNG into the Union Gas gas distribution system.

MR. VELLONE: I see. So in the evidence where you're talking throughout that there is no ability to inject RNG into the natural gas system, you are really specific to your natural gas system, the Enbridge pipeline system?

MR. McGILL: Well, I think as far as we are aware, that one site in Hamilton has the only operational facility in Ontario at this point in time. It has a fairly limited capacity. So in terms of magnitude, there is effectively no real RNG production in Ontario at this time, so I think we kind of generalize on that point. There is some capability, but it is very, very limited.

MR. VELLONE: So there is RNG injection equipment in Hamilton, owned, I guess, by Union Gas, or is it owned by the city --

MR. McGILL: No, the injection facility is -- part of the facility is owned by Union Gas, yes.

MR. VELLONE: Okay. Can we pull up APPrO Interrogatory No. 2, please? Maybe start with the question before you jump to the answer. It's a long question. Part B.

MR. McGILL: Yes, I see the question.

MR. VELLONE: The part of the question that I want to ask a follow-up on is really the second part of that full paragraph.

It was -- it was asking Enbridge to help the Board understand what your best estimates were with regards to the development of a potentially competitive market in RNG upgrading -- let's limit it to that -- if they chose to allow the regulated service versus if they didn't.

Do you see that second part of the question there?

MR. McGILL: Yes.

MR. VELLONE: Flip to part (b). I think you struggled with how to answer that, based on the way the first part of the question read.

Is that a fair understanding of your answer? You couldn't predict the future?

MR. McGILL: Well, I think it's very difficult to predict the future. I think we believe that the proposal that we have in front of the Board right now will help the RNG market and production facilities -- the development of production facilities in Ontario move forward faster than they would otherwise.

But in terms of what offerings others might provide, we don't have any knowledge of that at this point in time.

MR. VELLONE: Sure. The way this question was framed was specific to the Ontario jurisdiction. I'm wondering if you can take a crack, perhaps by way of undertaking, of answering a similar question, but specific to B.C. and Quebec with regards to how the RNG market evolved in those two different jurisdictions.

And the intent really here is to get on to the record some competing models, some competing regulatory models for the Board to consider.

MR. McGILL: Okay. I think we have an undertaking that we took earlier this morning, or earlier today, that basically would fulfill that request. So I'm not sure we need to take another one.

MR. VELLONE: I am happy if you are intending to answer roughly the gist of APPrO 2B in answering that other undertaking. I'm happy to have that added to that undertaking.

MR. McGILL: Okay.

MR. MONDROW: Just to be clear, the undertaking, as I recall it, Mr. McGill, was to provide the regulatory precedents from the other jurisdictions.

MR. McGILL: That's right.

MR. MONDROW: And like Mr. Vellone, if what you are saying is you will he expand that response to provide an analysis of the two markets and you want to do it under that number, that's fine. But it's a different question.

MR. McGILL: Yes, we can do that.

MR. VELLONE: Thank you.

MR. MURRAY: I think we'll just -- maybe actually for simplicity, it might be easier just to give it a new number, and we'll do JT1.13.

UNDERTAKING NO. JT1.13: TO PROVIDE THE REGULATORY PRECEDENTS FROM THE OTHER JURISDICTIONS; TO PROVIDE AN ANALYSIS OF THE TWO MARKETS

MR. VELLONE: Thank you. While we're on APPrO number 2, your answer to part A is pretty clear in regards to what you've been calling your optional service. Is that what you've been referring to the RNG upgrading facilities as, an optional service?

MR. McGILL: Yes.

MR. VEGH: Versus RNG injection, which you're calling -- is it a mandatory service, a must have, a must do?

MR. McGILL: Yes.

MR. VELLONE: Can we talk a little bit about the must-do portion, the injection facility? And this is really a follow-up to Ms. DeMarco's question. I'm trying to understand the scope of what the must do facilities will be and perhaps -- I'm an engineer by training, I'm going to go to the equipment.

Can you pull up figure number 1 in your application which shows, I think, a process diagram of what an injection facility might look like?

MR. McGILL: Yes, we have that.

MR. VELLONE: Okay. So my understanding is that an injection facility would include things --

MR. MONDROW: Just to put it on the screen -- sorry to interrupt. It's Exhibit B, tab 1, schedule 1, page 15.

MR. VELLONE: Referring to this diagram, figure 1 entitled "RNG production process and Enbridge service offerings", everything inside of the orange box entitled "injection systems", is that what you mean by the RNG facilities that must be part of the regulated utility?

MR. CHAGANI: It is everything inside the injection system box, and the pipeline.

MR. VELLONE: And when you say the pipeline, you are referring to the pipeline that I see that's connecting the injection system directly to the existing Enbridge natural gas distribution system?

MR. CHAGANI: Yes.

MR. VELLONE: You're not referring to a downstream pipeline that might connect an upgrade facility to your injection system?

MR. CHAGANI: I'm not sure I fully understand the question. So I -- there is going to be a pipeline that will go from the -- like the outlet of, let's say, the odourization tank in this example that would then go to our existing main, okay?

Within the injection station, there will be also pipelines that go from the metering to the odouring tank to the compressor, to the regulators and so on and so forth. All of those would be contained within our injection system.

MR. VELLONE: Understood.

MR. CHAGANI: So it would be any -- so there would be a custody transfer point. Anything downstream of the custody transfer point would be within the injection system.

MR. VELLONE: Would you be able to show me on figure 1 where the custody transfer would occur?

MR. CHAGANI: The arrow from the upgrade to bio-methane to the injection station would have a valve, or a custody transfer point in that...

MR. McGILL: Pathway.

MR. CHAGANI: In that pathway. So if there was a physical fence line, it would be on that fence line.

MR. VELLONE: And so the question I was asking is: If you go outside the fence line of the injection station, let's say that, and there needed to be a pipeline that connected to the upgrade facility, you would not propose that that downstream pipeline be part of your regulated utility. Is that correct?

MR. McGILL: I would refer to that as an upstream pipeline, so the pipeline connection between the upgrade to the bio-methane box in this figure. So there'd be a pipeline from that facility into the injection facility and at some point on that pipeline, presumably there would be a valve and that would be what I would suggest is the custody transfer point where we would take custody of the upgraded RNG and move it through the injection process.

And from the injection facility, then the gas would move into the gas distribution system through another pipeline connection, which would be downstream of the injection facility.

MR. QUINN: This may be helpful, Mr. McGill, You've said valve for a second time, and the panel has said valve.

Would it not be a meter? If you are doing custody transfer, would you not have a meter that is quantifying the stream of natural gas that went from party A, who is selling to Enbridge?

MR. McGILL: Well, okay, just to be clear, there's no transfer of ownership of the gas throughout this process.

So in our proposal, the untreated raw biogas and the final product upgraded to RNG, the title to that gas always stays with the biogas producer. But the...

MR. QUINN: So there is no custody transfer per se, in terms of title?

MR. McGILL: When I am talking about custody, I mean physical custody of the gas, not ownership of the gas.

MR. QUINN: So it's more like a common carrier type model, where you are metering for the purposes of understanding what goes in and going to be able to understanding what goes in, and are going to be able to redeliver that to what goes out somewhere else?

MR. McGILL: Well, yes. I'm not a hundred percent certain if there would be metering between the bio-methane facility and the injection facility. I don't know that that's always required.

It may be required in some instances, but we definitely need to be able to control what comes into the injection facility in the event that the gas coming into it does not meet the pipeline specification.

MR. QUINN: Okay.

MS. GRICE: So there has to be a way to physically prevent that from happening.

MR. QUINN: Or lock it in off, in a worst case scenario, yes, okay. That's a good clarification, because I was presuming a meter, and it doesn't have to be a meter in this case.

MR. McGILL: It may or not be a meter, but it would depend from one installation to the next.

MR. QUINN: Thank you very much. Sorry, John.

MR. VELLONE: That's okay.

MR. McGILL: Just another thing we'd like to point out is that all of these facilities would be located in typically one place on the customer's premises.

So it's not like there would be any significant physical difference or distance between the bio-methane upgrading facility and the injection facility. They would all be on the same site.

MR. VELLONE: Why is that the case?

MR. McGILL: I think it's, one, it is less costly; two, there is less concern with respect to moving upgraded RNG in a pipeline facility versus untreated bio-methane that could have high hydrogen sulfide content and other impurities in it.

So for a lot of different reasons, the most practical solution is to have all of these facilities contained in a small physical area.

MR. VELLONE: So I understand that answer would explain why you co-locate the upgrading facility with the production facility. I guess I don't understand why you have to co-locate the injection system.

MR. McGILL: I think from a physical standpoint it's not required, but I would refer to it as a standard practice. Everything we have seen in terms of the way these facilities are constructed, all of these aspects of the facilities are located in close proximity to each other. Yeah, and...

[Witness panel confers]

MR. CHAGANI: So if you -- just bringing your attention to the diagram, the first step in actually -- in our injection system is that first we monitor the quality of the gas, and that's why we actually use the word "valve", is because if the quality of the gas doesn't meet, we would shut the valve immediately. So that's the first step.

The second step would be metering and regulation to make sure that the pipeline -- the pressures meet the downstream pipeline pressures, and then there is odourization. In order for us to move gas on a public road allowance it would have to be odourized, it would have to be meeting the quality of CSAZ662, which is the pipeline distribution code. That's why we would co-locate the upgrading site, and that would not -- whether or not we own the upgrading site would not be in question, but we could co-locate the injection site right next to the upgrading so that all of these things can happen.

In addition to that, if you have a valve where you have to shut in the production of -- sorry, a valve where you have to turn away the bio-methane, you would have to have another pipeline that they would be able to take away that uncleaned gas, so again, there would be synergies to have all of that on to one site.

MR. VELLONE: That helps.

Going back to the previous answer, my understanding is that your answer was pretty honest. It said, This is how we've seen others do it, and that's why we're proposing to do it this way. Is that right?

MR. McGILL: Yes, that's correct.

MR. VELLONE: Which others are you referring to?

MR. CHAGANI: So the example with Hamilton is done in that fashion. The examples in B.C. that we've investigated are done in the same fashion.

MR. VELLONE: Quebec?

MR. CHAGANI: So Quebec is a little bit different, because one of the sites actually injects into TransCanada, so that -- it is not necessarily odourized gas that is going into TransCanada, it can't be odourized, but our understanding is that -- I think it is within a very short distance. I'd have to look up the exact distance -- but the sites are quite close.

MR. MONDROW: How many facilities are there in Quebec for upgrading of RNG?

MR. McGILL: As far as we know there's two operating today.

MR. MONDROW: Okay, one is near TransCanada, and the other one, does it co-locate the injection -- sorry, does it co-locate the injection system with the upgrade facility?

MR. McGILL: We don't know.

MR. MONDROW: Do you deal with any other jurisdictions other than B.C. and Quebec?

MR. McGILL: Not that we would have direct knowledge of.

MR. MONDROW: Okay. Thanks.

MR. VELLONE: So if you are co-locating the upgraded injection equipment near the same site, does that mean your injection equipment is facility-specific, it means it only works for that one RNG supplier?

MR. CHAGANI: It would be dedicated to that one RNG supplier. Typical -- like, it would have a meter set. Meter sets are fairly standard for the volume and the pressure of gas going through, so a lot of the equipment would be standardized, the odour tank would be standardized, but specifically it would be dedicated to that one customer.

MR. VELLONE: And if that customer went out of business for whatever reason, who would carry the cost for the injection equipment?

MR. CHAGANI: Within our -- one of our interrogatory responses we said that for -- we would follow a typical process for acquiring security from our customers, so in this case we would have some type of security with the injection customer.

MR. VELLONE: So that in the event they do go out of business, you are not going to recover in rates the costs that you incurred to build this equipment.

MR. CHAGANI: That's correct.

MR. VELLONE: Other ratepayers would be held harmless? Is that the intent?

MR. McGILL: Yes, we would exercise whatever security instrument we had to recover the unrecovered costs of the facility.

MR. RUBENSTEIN: But you are not guaranteeing that if a customer goes out of -- if a customer goes out of business, ratepayers would be held harmless?

MR. McGILL: I don't know that we can guarantee that on a one-for-one dollar basis, but what I can tell you is this is a typical practice where we are extending dedicated facilities for a single customer. We typically enter into a financial security agreement with them. That can entail irrevocable letters of credit and things of that nature to give us the protection we need to mitigate that risk of the unrecovered cost of those facilities.

MR. RUBENSTEIN: And have you ever entered into -- or have you ever constructed dedicated facilities for a single customer of this financial magnitude without aid in construction and so on?

MR. McGILL: Off the top of my head I couldn't say. I think -- I would expect that probably in the past -- like, you are talking about a contribution in aid of construction, which is different from acquiring security from that customer, so in either case, whether there was a contribution in aid of construction or not, if it was a dedicated facility we would still be seeking the same kind of financial assurances, it is just that if there was a contribution in aid of construction, the capital costs that we were trying to secure would be less.

MR. RUBENSTEIN: So let me break it down: Have you ever constructed dedicated facilities for a single customer of the magnitude that you expect for either the injection or the upgrading system where you have not required the aid in construction, but required letter of creditors, or maybe not?

[Witness panel confers]

MR. RUBENSTEIN: Feel free to answer this by way of undertaking.

MR. McGILL: So the way I understand your question is you are asking if we have ever installed dedicated facilities that were subject to a capital contribution where we didn't seek financial assurances?

MR. RUBENSTEIN: Have you ever constructed dedicated facilities thereafter -- if there was or was not aid to construction that you asked for, so the remaining amount that essentially you were charging the customer for, of the size that you are expecting for the injection or the upgrading system?

MR. McGILL: Well, what I can say is that we have installed dedicated facilities to large customers that are on -- in terms of dollar value, the same order of magnitude where we did obtain letters of credit in order to secure those investments.

We can recall at least two specific examples in the more recent past, within the last five to ten years.

MR. RUBENSTEIN: And does the financial assurances that you will require for from them, letter of credit or something else, does that assure that the remaining value that essentially you will be -- that if the company goes out of business, that you will recover the full value of the remaining life of those assets?

MR. McGILL: Yes, the financial assurances are valued such that we would recover the undepreciated capital cost of those facilities.

MR. RUBENSTEIN: As well as removal, or any other...

MR. McGILL: Decommissioning costs, yes.

MR. VELLONE: Okay. So going back to the diagram in figure 1, and just to make sure I've got it all in my head, your injection system would include gas analyzer testing the RNG when it comes in, metering, compression, telemetry, regulation and odourization equipment, as well as that other list -- associated valves, pipelines, and things like that.

MR. McGILL: Yes.

MR. VELLONE: A pipeline to get you back to the Enbridge distribution system?

MR. McGILL: Yes.

MR. VELLONE: Anything I'm missing?

MR. McGILL: At a high level, I don't think so, no.

MR. VELLONE: No storage tanks or anything like that you're thinking about here?

MR. McGILL: Storage tanks for the odourant. I don't think we would have any storage tanks associated with the compression equipment, if compression is required at a site. There is some filtering equipment that would be sort of in that other category of smaller components of the system.

MR. VELLONE: That helps, thank you. You've spoken a bit this morning about utilizing the EBO 188 feasibility guideline as a process that you are using to determine the rate for this new service offering. Is that -- is my understanding of that correct?

MR. McGILL: That's correct.

MR. VELLONE: So my read of EBO 188 is that it applies to natural gas expansions, and doesn't necessarily apply to

RNG upgrading or RNG injections. Is that -- I mean, am I missing something?

MR. McGILL: Well, I think at the time that EBO 188 was drafted, RNG upgrading and injection facilities were probably not contemplated at the time.

But what EBO 188 does give us is it gives us a construct or a framework as to how we determine the economic feasibility of gas distribution expansion projects. And what we're doing is we're using that methodology to determine the rate that's required to recover the cost of these facilities and operating these facilities over their contract life on a net present value basis, which is consistent with the EBO 188 rationale and concept.

MR. VELLONE: So it's a novel application of the principles in EBO 188, to these new...

MR. McGILL: Well, I -- not necessarily. I think we spoke earlier with respect to one of the Board Staff questions.

We apply the EBO 188 framework in pretty much exactly the same way in order to determine demand charges under rate 125. We use that framework to determine the requirements for capital contributions in aid of construction, which the Board has previously ruled are our rate.

So I think we are on firm ground with respect to applying the EBO 188 rationale in the way we have to determine the rates for these services.

MR. VELLONE: But there's nothing in EBO 188 that says it must apply in these circumstances?

MR. McGILL: No.

MR. VELLONE: Can you pull up your response to CBA Interrogatory No. 2, part 3?

MR. McGILL: Yes, we have that.

MR. VELLONE: So your previous discussion where we pinned down by what you meant by injection facilities may answer this, but I'm just trying to understand.

When you say there is no ability to inject into Enbridge's system, what did you mean by that?

MR. McGILL: So at the moment, there are no RNG injection facilities that are attached to our gas distribution system.

MR. VELLONE: And when you say RNG injection facilities, that's the equipment that we just talked about a minute ago?

MR. McGILL: Yes.

MR. VELLONE: Are there other ways that RNG could be injected into the Enbridge system, other than use of one of these types of injection facilities?

MR. McGILL: I don't believe so, not without being in violation of the codes and standards we operate under.

MR. VELLONE: So, for example, if RNG was injected into the Union Gas pipeline system and then made it downstream into yours?

MR. McGILL: Yes.

MR. VELLONE: So Hamilton would be a pretty good example of where that would be happening?

MR. McGILL: But that's not directly injected into our gas distribution system.

MR. VELLONE: Okay, fair enough. I guess -- in your market research that you've done, have you come across any examples of where an RNG injection station was not specific to an RNG production and upgrading facility? You build it and they come to you, as opposed to the other by a around?

MR. McGILL: I'm not aware of any, no. I think -- I think, based on the physical practicalities of trying to do that, I just can't see how it would work in any kind of cost-effective way.

There are different models where you could have, in say an agricultural scenario, where you have a number of farms that transport their waste to a central digester facility, and it would be at that location that you would include -- or build your upgrading facility and your injection facility and attach it to an existing pipeline system.

So you would have some kind of transportation network of probably trucks that would pick up the waste and bring it to a central location. Otherwise, I don't think it would be economic to have 30 or 40 very small digesters and upgrading facilities and injection facilities scattered across a large geographic area,

So I think there are different models of how to consolidate the feedstock in such a way that it becomes economic. But to have a central injection facility with a number of pipelines running from upgrading facilities to it, I just don't believe that you could do that in a cost-effective way.

MR. VELLONE: Fair enough. Can we pull up the response to Energy Probe interrogatory number 3, please, and specifically part C of that question.

MR. McGILL: Yes, we have that.

MR. VELLONE: So in this question Energy Probe was asking whether, setting aside RNG for a minute, whether Ontario gas producers are required to use Enbridge assets for injection services, and my understanding of the answer is that, yes, they are. You would require them to use Enbridge assets for injection services?

MR. McGILL: Yes.

MR. VELLONE: How would those assets differ from what you just walked me through for RNG injection services, for a standard natural-gas injection?

MR. McGILL: Well, they would be less complicated in that we wouldn't be concerned about -- yeah, so I think if you go to part F of the response to that question, I think we've set out some of the differences between RNG and sort of fossil-based natural gas and what the different requirements are with respect to getting biogas up to pipeline-quality RNG.

MR. VELLONE: So just going back to figure 1 in the evidence again. I'd like you to help me translate these different properties of standard natural gas and RNG into the facilities that would be utilized to inject standard natural gas as opposed to RNG.

So looking at figure 1, what wouldn't you need?

[Witness panel confers]

MR. McGILL: So if we just look at the injection system portion of the overall system, we would have different testing requirements for traditional natural gas versus upgraded RNG. We would have metering, probably telemetry systems. As far as I know we don't have any compression on our system today, but there would be a requirement to regulate the flow of gas coming from that local source into our system, and we would have to odourize the gas where it's introduced into our system.

MR. VELLONE: And with a standard natural-gas injection system, would you also propose to co-locate that at the gas producer's site?

MR. McGILL: Yes, typically that's the case, so in the case of our major gate stations that take gas off the TransCanada system, those facilities are all located on the same site, and they include, because you have the drastic pressure differentials, there is also equipment required for heating and whatnot to make sure the facility doesn't freeze up.

And in the case of the one local producer that we transport gas for today, that injection facility is located -- I can't say for certain whether it's on their property, but it is either on their property or adjacent to it.

MR. VELLONE: Okay, that's helpful.

Can you pull up the response to APPrO interrogatory number 5?

MR. MURRAY: Mr. Vellone, I just wanted to do a time check to see kind of where we are with things.

MR. VELLONE: I'm on my last set of questions.

MR. MURRAY: Thank you.

MR. VELLONE: Part F, the answer to part F. It's showing on the screen.

MR. CHAGANI: Yeah, we have that now, sorry.

MR. VELLONE: So you have one contract in place, and my understanding that's with the City of Toronto; is that --

MR. McGILL: That's correct.

MR. VELLONE: Is that contract dependent upon the Board granting the relief requested in this application?

MR. McGILL: Well, the contract has been drafted in such a way that we would be able to go ahead and provide the services, whether or not we get the relief we're requesting in this application.

MR. VELLONE: Okay, and I -- with regards to the business model that's proposed for this application, I guess my question goes back to Mr. Rubenstein's question, which is why couldn't you just lower the upgrading fees or injection fees that you are charging these customers and charge them a capital contribution like you do -- or contribution in aid of construction like you do with your other customers? I guess, why the special model?

[Witness panel confers]

MR. McGILL: Typically we don't charge customers joining the system capital contributions or charge them for contributions in aid of construction. Contributions in aid of construction are only required when the base rate applied to the estimated volume that that customer is going to take don't generate enough revenue to cover the cost of those facilities over their accounting life on a net present value basis, so that's typically not what we do.

MR. VELLONE: So I'm just trying to unpack that answer. So we were looking earlier at Appendix number 5, I believe it was, to your original evidence.

MR. McGILL: Yes.

MR. VELLONE: And I thought that showed that you did require a kind of subsidy from ratepayers over a certain period of time and then that subsidy was paid back over the life of the asset; is that not...

MR. McGILL: Well, I think -- I don't know that "subsidy" is quite the right way to put it. I think in our business today, you know, for example, if we are following the EBO 188 guideline with our -- in our standard day-to-day business, the average cost to add a residential customer right now is about $3,800. The average gas bill for that customer is about $900 a year, so it is obvious that that customer, on average, is not returning the full cost of providing service to them from day one.

So in order to provide them with that, in essence, levellized rate of $900 per year, they operate in a deficient -- or revenue deficiency situation for some number of years until depreciation takes the cost of the asset down to the point where that $900 a year or the distribution margin that's included in that exceeds the cost of providing them service in any given year.

So what you have happening is you have deficiencies typically in the early years that are returned in the later years, and the feasibility test we operate under requires us to have a investment portfolio PI of 1.0 or greater, so what that does is it means that those new customers, although they are under-contributing in the early years, over the asset life they are not, so that there is no cross-subsidy coming from existing customers to bring them on to the system if we're following that feasibility guideline.

So the same thing holds true in what we're proposing here. So it's that temporal difference between revenue requirement and revenues that's being tracked, and in most cases you're deficient in the early years and you have sufficiencies in the later years, and over the life of the asset they balance each other off to give you a PI of 1.0, which is indicative of net present value of zero, which is, nobody won, nobody gained, so we are applying that same rationale here, so this is no different than any other customer we would add.

MR. VELLONE: So if the temporal difference is a concern for ratepayers, is one way to solve that by charging an upfront capital contribution? Let's not call it a contribution in aid of construction, because you are disagreeing with that. But if you just charge them a capital contribution, can you get rid of that temporal difference?

MR. McGILL: It may. It would reduce the capital cost that -- actually, I don't think it would the way we're doing this, because you would reduce the capital cost of that project, which would reduce that project's revenue requirement, which would reduce that project's rate.

So you would still have the same profile of deficiencies and sufficiencies over the same period of time with a capital contribution. It's just that the sizes of the whole thing becomes less.

So I don't think the answer to your question is yes. It would be the same, but smaller.

Now, what did we did do and we did test in one of the interrogatory responses is if you move off of a levellized rate so that you charge more in the early years and less in the latter years, then you wouldn't have those revenue deficiencies and sufficiencies.

But that would undermine the entire service by not being able to offer it at a levellized cost or rate to those customers.

MR. VELLONE: Recognizing that I've gone over time, we're going to park it there, I think.

MR. MURRAY: Mr. Buonaguro?

MR. BUONAGURO: Thank you. Are we going to have lunch?

MR. MURRAY: Well, I actually think we've only be going for less than a hour since we came back from the break. We actually only started back about 11:55. So I'd like to try to get through one more before lunch, if we can.

MR. BUONAGURO: Sure. I put in for 30 minutes, but I'm going to try to come in well under that. If I am, I'll be the first person today, so...

EXAMINATION BY MR. BUONAGURO:

Good afternoon, panel. Michael Buonaguro, I'm counsel in this instance for the Canadian Biogas Association.

A lot of the topic areas I was going to cover have at least been touched on, if not discussed in detail. So I'm going to flit around a little bit just to clean up some points that I wanted to follow-up on.

If you could pull up the diagram that you were speaking to Mr. Vellone about, in terms of -- I have the reference here. It's B1.1, page 15 -- that's it -- from the evidence.

And I noticed on this diagram -- and this relates to a series of questions I was going to ask, but this is a simpler way of doing it -- under injection system, it says "compression or regulation".

Can you explain why on the injection side there seems to be a disjunctive option; there could be compression or there could be regulation?

MR. CHAGANI: So the biogas producer, if they're managing the clean-up, the output of the clean-up facility could give us gas at a higher pressure than our system, or a lower pressure than our system. And so in that case, if we get it at a lower pressure, we would increase the pressure to match the pressure of the system. And if it's a higher pressure, we would decrease it with regulation to get it down to meet.

MR. BUONAGURO: I see. So from a compression point of view -- and I noted in the main evidence and interrogatory responses, you talk about compression in the injection side -- the needs for any particular customer will depend on how they're delivering the gas from a compression point of view?

MR. McGILL: It will depend on where the facility is located in relation to our system, and what the operating pressures in our system are at that location.

So let's say if I've got an existing part of the gas distribution system that has a maximum operating pressure of 300 psi, and the RNG coming out of the -- coming into the injection system is at 200 psi, I've got to use compression to increase that pressure above the 300 psi in order to get the gas to flow into the pipe.

So conversely, if you have the opposite situation where the gas coming out of the injection facility is at a higher pressure than what we can allow in the adjacent pipeline, you have to use regulation to cut the pressure of that gas coming into the system so that will be at a pressure that's acceptable to our system, so we don't over-pressurize that part of the system.

So it could be either or, depending on the location and the characteristics of our gas distribution system in that area.

MR. BUONAGURO: Thank you. In this example, I guess, this sort of assumes that if -- I think it assumes that if Enbridge is doing the upgrading on the same site as they're also doing injection services, then you would include full compression as part of the injection system?

MR. McGILL: Yes, if compression was required, it would be part of the injection facility.

MR. BUONAGURO: But in another scenario where a company has decided to do the upgrading itself, it may be the case that they're able to deliver it -- the upgraded renewable natural gas at a compression or pressure that all you have to do is regulate it?

MR. McGILL: Yes, that could be the case.

MR. BUONAGURO: But it's basically RNG producer specific; it depends on the situation?

MR. McGILL: Yes.

MR. BUONAGURO: Fair enough. I just wanted to confirm that. You were -- and again you were speaking to Mr. Vellone about injection systems, and you mentioned specific example of an injection site for traditional, I'll call it, natural gas where Enbridge is injecting gas into its own system.

MR. McGILL: Yes.

MR. BUONAGURO: There was an interrogatory response, Exhibit I, tab 1, EGD.I.EP3, so I guess the first set of interrogatory response is EP3 and it refer to, I think, that same system. It says in response A:

"Enbridge does not currently purchase any Ontario natural gas production. Enbridge currently owns and operates one gas custody transfer station where natural gas produced in Ontario is injected into the company's gas distribution system for transportation to Dawn."

Is that the same facility?

MR. McGILL: That's the same facility that I was referring to earlier, yes.

MR. BUONAGURO: So that's the one example of Enbridge running an injection site for something other than RNG; is that fair?

MR. McGILL: Yes.

MR. BUONAGURO: Okay. And my understanding from this morning, if I got it correctly -- and throughout the interrogatory responses, I think this is true -- Enbridge owns and operates that facility?

MR. McGILL: The injection parts of that facility, yes.

MR. BUONAGURO: Okay. And would Enbridge have had to seek special permission from the Board to purchase and own and run and include in rates that injection facility?

MR. McGILL: I don't know. I think that facility is a very old facility, and I'm just not sure whether there was special dispensation required from the Board with respect to that or not.

[Witness panel confers]

MR. McGILL: We were just saying that in terms of that physical facility, it's probably been there since the 1960s. So whether or not the Board considered it on a stand-alone basis or not, I don't know. I would be surprised if they did. I think it just would have been treated as part of our general gas distribution system.

MR. BUONAGURO: But presumably, it's been part of rate base ever since it was installed?

MR. McGILL: I would expect so, yes.

MR. BUONAGURO: Thank you. Somebody's pointed out it is probably fully depreciated by now, unless there has been upgrades?

MR. McGILL: That would be my guess, yes.

MR. MONDROW: Unless the producer paid for it.

MR. McGILL: Pardon me?

MR. MONDROW: Unless the producer paid for it, which is another possibility.

MR. McGILL: That's a possibility. Like I said, it goes back quite a ways.

MR. MONDROW: Understood.

MR. BUONAGURO: I think you just said it was included in rate base, though.

MR. MONDROW: That's why I'm asking. We don't know that. You're assuming...

MR. McGILL: Presumably, it would have been.

MR. BUONAGURO: Presumably, the producer paid something for the service, and continues to pay for the service?

MR. McGILL: Yes, we have an agreement in place to transport the gas for them from their site to Dawn. And I think we explained that elsewhere in the interrogatory responses; that's done on the basis of an exchange agreement and we either pay or receive the differential in the transportation cost to the CDA.

MR. BUONAGURO: Right. So it sounds to me like what you're saying is that the injection component of whatever they're paying for is a sub-component of an overall contract to move the gas?

MR. McGILL: Yes.

MR. MONDROW: Sorry, Michael, could I just ask a question?

MR. BUONAGURO: Yes.

MR. MONDROW: Does that producer pay for an injection service?

MR. McGILL: No, they don't.

MR. MONDROW: Okay. What they pay you is for a transportation service?

MR. McGILL: Yes, effectively a transportation service. It's a gas exchange agreement that that operates under and as far as I know, there is a monthly administration fee and it's just basically either charging them or paying the toll differential to the CDA with respect to that gas.

MR. MONDROW: But you do understand, if I understand your statements a few minutes ago, that the injection facility cost was at least at one-time included in rate base.

MR. McGILL: I believe it was, because that entire facility originally was part of the old Consumers Gas system.

MR. MONDROW: And so it just would have been included as kind of a distribution facility?

MR. McGILL: Yes.

MR. MONDROW: Thanks. Thanks, Michael.

MR. BUONAGURO: Thank you.

Now, I think you spoke with Mr. Rubenstein at some point about this, but I'm just going to follow up. Exhibit I.2.EGDI.SEC.16. And this talks about financial assurances that are to be provided by RNG producers that take either/or of the services, and this talks about article 13, response B. It says:

"Article 13 of the biogas service agreement addresses financial assurances. The treatment of financial assurances will be consistent with Enbridge's existing practices."

And I took it from your early conversation with Mr. Rubenstein, is that the intent of the proposal in this case is to extract from RNG producers, if I can use that word, the same financial assurances that you would extract from customers in similar situations in terms of securing the revenue stream from those customers over the necessary lifetime of whatever the undertaking is, in this case an undertaking to provide either upgrading and/or injection services?

MR. McGILL: Yes, that's correct.

MR. BUONAGURO: All right, thank you.

Now, just flipping to -- this is Exhibit I.2.EGDI.APPrO.7. And at part B the answer was -- and this has to do with injecting gas into your system, I assume. It says:

"Enbridge can only accept gas when system capacity is available. If applicable, the producers would be provided options for connection to the Enbridge system. In some cases connection to a different system or pipeline can increase the takeaway capacity, and then the costs of the connection to the Enbridge system will be included in the RNG injection services fee."

MR. McGILL: Right.

MR. BUONAGURO: And I think you've spoken a little bit about this already, but I want to get some further detail if you could.

It sounds to me like you can't just connect to any part of your distribution system and get the same injection capacity, right?

MR. McGILL: That's correct, yeah, so what we're trying to get at in this response is, is that if there were -- if we had two parts of our pipeline system that were in reasonably close proximity to an RNG production site, it could be that in one of those parts of the system our ability to take gas away from that site is more constrained. So if that part of the system was operating at or near its maximum pressures more often than not, then there would be periods of time where we just couldn't take the gas into the system, and then you'd either have to shut down the upgrading facility and, you know, the gas would either have to be reprocessed back through a digest or a flared.

But then, you know, there could be another part of our system that is slightly further away that does have the capacity to take the gas or take the RNG away more of the time, so then you would look at it and say, well, in this specific set of circumstances are you better off to do the shorter pipeline connection to the part of our system that has the limited takeaway capacity, or spend more money to get to another part of our system that has a greater takeaway capacity. And the economics of that would be unique to every situation.

MR. BUONAGURO: Okay. Thank you, that helps.

Now, does that -- let's say you have a situation where you've connected someone at a particular point after going through that analysis and figuring out, from their perspective, an optimum connection point.

Intuitively I'm concerned that the takeaway capacity -- I think that's what you've referred to -- yeah, the takeaway capacity for any particular area in your system, including the area that we're talking about in the hypothetical, could change over time based on a number of factors; is that true?

MR. McGILL: Yes, it could.
MR. BUONAGURO: So how does that affect -- or how could that affect the operation of that particular producer over time in terms of its ability to inject into the system?
MR. McGILL: Again, it would be circumstantial and sort of case-specific, but in an instance where we had load growth in that area, our takeaway capacity is likely to increase, so that there would be potential for that producer to introduce more gas into our system than otherwise.
If we lost load in that part of the system, then it is likely that the takeaway capacity would decrease and we would be able to take less of the RNG from that production facility.
So that's one of the reasons, in order to try and, you know, reduce the risk to the company and the ratepayers associated with the service, we've gone to this levellized fee whereby the biogas producer will pay the same amount regardless of the amount of gas that's injected into our system.
MR. BUONAGURO: Right, so -- and what you're telling me there is that -- I think, is that if -- and from a producer's point of view, if the ability to inject gas in the system happens to go down over time, which, you haven't talked about how likely that is. I think you're saying that as long as load growth goes up it should actually increase over time, but if it goes down over time that

doesn't change how much they're paying under your proposal.

MR. McGILL: That's correct.

MR. BUONAGURO: Thank you. And lastly, actually, just to summarize what I understood from a lot of the conversation you had this morning with, I think, Board Staff and Ms. DeMarco, there was a lot of discussion about environmental attributes, and I'm -- and I told Ms. DeMarco I'm guilty of misusing the term, maybe using it too generically or not narrowly enough, but my understanding is even if I use it in the broadest sense of the word, environmental attributes, your proposal for the pricing of the Rate 400 and the Rate 401 services essentially ignores environmental attributes; is that fair?

MR. McGILL: Yes, we don't take that into account in the determination of what the rate would be under either one of those rate schedules.

MR. BUONAGURO: Right, so you could offer the same sort of pricing model for conventional natural gas coming out of my backyard in downtown Toronto -- I wish that would happen -- but it would still hold as a pricing model?

MR. McGILL: Yes, and -- depending, yes, so the pricing model would hold true, yes.

MR. BUONAGURO: Okay. Let me just check to make sure I didn't miss anything.

No, thank you, those are my questions.

MR. MURRAY: I think now is probably a good time to break for lunch, but if I could ask people take a short lunch break and come back at ten to 2:00.

--- Luncheon recess taken at 1:05 p.m.
--- On resuming at 1:55 p.m.

MR. MURRAY: Welcome back, everyone. I think we now are now on Ms. Girvan for CCC.

EXAMINATION BY MS. GIRVAN:

MS. GIRVAN: Thank you. I will give you the reference for each of them.

Could you first turn to Board Staff number 1, please? If you could just scroll down. I'm looking at my own -- sorry, I'm looking at my own computer and it wasn't scrolling down. If you turn to the third point, it says that:

"Enbridge is aware of other organizations that capable of providing the design of RNG upgrading facilities and supplying the necessary equipment."

Could you tell me how many other organizations are doing this when you talk about the ones that are -- other organization that are capable?

MS. FRASER: And the engineering --- .

MS. GIRVAN: Any engineering firm.

[Laughter]

MR. CHAGANI: I guess there's two elements to that, right? The first one is the design of the RNG upgrading facilities, and there are a number of engineering companies that would be able to support that design.

And then the second piece is the equipment providers. So I don't know the number of equipment providers, but there's at least a dozen companies that can do similar functions of cleaning the biogas to meet pipeline specifications.

And Enbridge, if we were undertaking the activity, would hire one of these equipment providers to actually like build the membranes and clean-up equipment that we would then get installed.

MS. GIRVAN: Okay, thank you. If you could turn to APPrO number 2, please. In part C, I'm trying to understand the answer there about the risk faced by ratepayers will be equivalent to those they face today in respect of any other investment. Could you explain that to me?

MR. McGILL: Yes, I think -- we talked about this earlier today, and that -- so the EBO 188 guideline is designed to ensure that new customers aren't subsidized by existing customers of the utility.

And so what -- and that test is based on a discounted cash flow calculation that's supplied to the net revenues of the project and compares that to the net present value of the cost of the projects and the result. And the result, in order to go ahead, needs to be a PI of 1.0 or higher.

So what that means is that on a forecast net present value basis, there is no cross-subsidy if you are at a PI of 1.0 over the life of those assets.

But what you do have, as I described earlier, is that temporal revenue deficiency in the early years that's made up by revenue sufficiencies in the latter year, so that over the course of the life of the asset, you end up with a -- in the case of a PI of 1.0, a net present value of zero, which infers that there is no subsidy from existing ratepayers to support the addition of those new customers.

So that logic applies directly to the way we've gone about setting up the rate-setting process for rates 400 and rate 401, so that if you're applying EBO 188 as the feasibility test for any other utility investment, you still face that same early year revenue deficiency and latter year revenue sufficiency with any other investment the utility would make.

So on that basis, it's our position that the risk to ratepayers is no different than it would be for a regular main extension, or the addition of subdivision customers, or any of our other regular business.

MS. GIRVAN: And it says -- I may have missed this, but how long are these contracts?

MR. McGILL: In the example we're showing, it's a 20-year contract. They could be anywhere from 10 to 20 years.

MS. GIRVAN: And you are asking the Board for approval of that, anywhere between 10 and 20 years?

MR. McGILL: Well, we would set the rate to recover the costs over whatever the contract life span was. So if it was a 15-year contract, let's say, we would set the rates such that we would recover all of our cost on a discounted basis over that 15-year contract life.

MS. GIRVAN: Okay. But what do you think is going to be the standard? Is it ten years? Is it 15? Is it 20?

MR. McGILL: So there's two considerations. One is the estimated physical life of the upgrading facilities is 20 years. So that kind of sets the maximum contract span. And then the other requirement of EBO 188 is that for industrial customers, we do the feasibility test over 20 years --not longer than 20 years. So we're consistent with that element of EBO 188 as well.

MS. GIRVAN: But do you -- do you think they are all going to be 20 years, or some of them might be 10?

MR. McGILL: I don't know.

MR. CHAGANI: We expect that the feedstock would play into that as well. So there's some biogas feedstock that, like landfills for instance, that have a shelf life or a point where they won't be generating biogas anymore.

So we would work with the producer to determine the lifetime that they see as best. And in the event that they don't produce, again our rate is fixed, a set amount every single month, so they would have to continue to pay us. So it would be in their best interest to work with us on what that timeline looks like.

MS. GIRVAN: So you are not asking the OEB to approve the contracts; you are asking the OEB to approve the rate?

MR. McGILL: Yes, what we're asking the Board to approve is the rate-setting methodology, because we'd end up with a unique rate for each facility.

MS. GIRVAN: Okay. All right, thank you. Mr. McGill, you spoke earlier about the accelerated capital cost reduction, and that that's an advantage that Enbridge would have in this case?

MR. McGILL: Yes, it is the accelerated capital cost allowance for tax purposes. So in terms of deducting the capital cost of these investments for the purposes of determining income tax payable, you are allowed to depreciate these assets on a faster timeframe than what you would typically see because they are supporting the production of renewable energy.

MS. GIRVAN: Doesn't that give you an advantage over other potential upgraders?

[Witness panel confers]

MR. McGILL: So the capital cost treatment would apply the same to anyone that's entering into this line of business, because that's part of the Income Tax Act. It's outside of, you know, sort of our rate-setting scope.

MS. GIRVAN: But I thought you said that's an advantage that you have doing -- dealing with the utility.

MR. McGILL: So you have -- okay, so if you were having dedicated start-up company that had no other sources of income other than providing these RNG services, then they would have no income to apply, or very little income to apply that tax deduction against. And so they wouldn't get the tax -- the same kind of tax benefit that a larger organization that already has taxable income flowing into it would receive from being able to take advantage of the accelerated capital cost allowance.

MS. GIRVAN: All right, thank you. Could you turn to

CBA number 2, please?

I think Mr. Buonaguro was asking you about this, but there is one production facility operating currently in Ontario, that's correct?

MR. McGILL: Yes.

MS. GIRVAN: And how long do you think it will take for more suppliers to be up and running?

MR. McGILL: Well, we -- I think on average, it's probably -- from the time the contracts are executed, it's probably about a two-year lead time to get one of these facilities built and installed and up and running, so, you know, we have one facility that is in the process of being designed right now. I think the target date to bring that into service is late 2019, so, you know, that's sort of the order of the time scale it takes in order to get these things built and up and running.

MS. GIRVAN: And will this be dependent on government funding of the actual biogas?

MR. McGILL: Not necessarily. If the RNG is being sold to either parties that seek it today inside Ontario or parties that seek it outside of Ontario today, then that means there's a market for the RNG and that a need for someone to facilitate the production of that RNG.

MS. GIRIDHAR: So, you know, RNG, we are finding in our discussions with municipalities that there is a couple reasons why they like RNG. Some of it is, respond to that community energy plans, but several of the larger municipalities that also have green-bin organic collection systems, they're interested in using RNG for transportation, so a number of jurisdictions have -- actually converting their garbage collection trucks to CNG, or compressed natural gas, and then, you know, they are attracted by the notion of generating renewable natural gas from the waste collected and using it to fuel their trucks, so sort of a -- what is it you call it --

MR. McGILL: Well, it's a circular economy, so --

MS. GIRIDHAR: Circular economy.

MR. McGILL: -- so I think it was late in 2016 the provincial government actually tabled proposed legislation. I think it was called the Circular Economy Act. Part of this was bringing forward a prohibition on putting food waste into landfills, so that actually you could capture that waste and turn it into some kind of renewable fuel source, so that legislation didn't go forward, but the prohibition on food waste in landfills was, again, looked at last year. There's no legislation in place as of yet with respect to that, but that's another consideration for the municipalities.

If they're forced in -- those that don't have green-bin programs today, there's a good likelihood that they will be required to implement that type of program in the not too distant future, which means they need to find a home for this food waste that they'll be collecting.

MS. GIRVAN: Okay, could you turn to FRPO number 1, please? Could you explain to me what the underlined sentence means?

MR. McGILL: That:

"Enbridge will enable the movement of that gas to a terminal location of the producer's choice through the various service offerings Enbridge provides its customers today."

So that -- so if you follow up on Malini's example, so let's say you're looking at a municipality that is producing RNG and they want to use it to fuel their garbage trucks, so typically the garbage trucks wouldn't be located at the same site as the RNG facility would be, so that we would enter into gas transportation agreements, as we would to move gas today on -- for -- on a, you know, more traditional basis, to move the gas from the RNG production site to the site where that customer wants to use the gas. So in this example it would be an NGV refuelling station dedicated to refuelling those garbage trucks.

MS. GIRVAN: Okay, you talked earlier about an example of someone that's 20 kilometres away from your existing system?

MR. McGILL: Yes.

MS. GIRVAN: And it's still not clear to me who pays for that 20 kilometres of pipe.

MR. McGILL: In our proposal that cost would be recovered through the injection service fee.

MS. GIRVAN: Okay, okay, and you mentioned that you have now an agreement with Toronto Hydro?

MR. McGILL: No, it is the city of Toronto.

MS. GIRVAN: The city of Toronto, sorry. And can you tell me how that's become viable? Are there subsidies from the city of Toronto for that program?

MR. McGILL: Well, with respect to our relationship with the city of Toronto there is no provincial or other government subsidies that we're aware of. I am aware that the city of Toronto did get -- or I believe has been awarded some money from the province to offset the cost of building the facility.

MS. GIRVAN: Okay, because you had said it doesn't matter if it's in the utility or out of the utility, it's still a viable opportunity.

MR. McGILL: I don't know that I said that specifically, but the city of Toronto is going ahead with the project, you know, even though the province -- or the new provincial government is in the process of unwinding the cap-and-trade program.

MS. GIRVAN: But regardless of whether or not you get approval from the Board to have this program in the utility.

MR. McGILL: Yes, we're prepared to go ahead with the city of Toronto and honour the commitment -- the contractual commitments we've made to them.

MR. QUINN: I just wanted to ask a follow-up question in that area too, because I think the words you used is "the way the contract was drafted".

[Witness panel confers]

MR. McGILL: Sorry --

MR. QUINN: No, no, I want to respect -- you were talking. I just -- I was following up on Julie's question. I think the words you used is "way the contract is drafted" --

MR. McGILL: Yes.

MR. QUINN: -- "whether we get approval or not we would still proceed with the city of Toronto project"; do I -- got that right?

MR. McGILL: Yes.

MR. QUINN: Okay. So my question is -- and without getting into the details of the contract -- I'll respect that, but if the Board does not approve the 401 rate for injection as part of this proceeding, are you saying that your drafting of your contract would allow you to support Toronto -- city of Toronto in using its facility on its own? So in other words, the gas doesn't hit your system.

MR. McGILL: Well, I think the -- given the nature of the location, I think the gas would have to enter our system in order to be useable. I don't think the city could, you know, use the volume of RNG that would produce at the site where the production facility is.

MR. QUINN: Okay.

MR. McGILL: So we would have to move the gas for them somewhere. That would be up to the city to decide where we would move that.

MR. QUINN: But your mechanism and your rate to inject the gas, if it's not approved by the Board, what authorization would you have to take that gas into your system?

MS. GIRIDHAR: I think that is the case we are making here. There is a demand for RNG. We have a customer that is seeking the service, so certainly the injection service is something that we would -- that the city of Toronto would like to have approved so that they can inject that RNG into the system.

MR. QUINN: But again, I don't want to -- it's in the transcript, but if you are saying you are going to go ahead whether this is approved or not, I'm -- I don't understand how you are going to do that without Board approval.

MS. GIRIDHAR: I think the context on the -- was specifically with respect to the upgrading service, in that it has been designed -- the upgrading service has been designed on the principles we have here, and we would move forward to provide them with the upgrading service, but I think it's fair to say that we are looking to have the means to inject RNG into our system as well.

MR. QUINN: So that -- the premise is that the 401 service has to be approved by the Board in one way, shape, or form. The 400 service could be something that the Board decides differently, but to be able to have the gas enter your system, are you -- you would need some kind of rate to do that if you are going to be asking...

MR. McGILL: We would need a mechanism to recover the cost of that injection facility.

MR. STEVENS: I think to be fair, Dwayne, we'd have to understand the basis on which the Board declined to approve these services.

MR. QUINN: Okay. If --

MR. STEVENS: If, for example, the Board declined to approve the injection service because for some reason it was viewed to be a competitive service --

MR. QUINN: Right.

MR. STEVENS: -- that might not close the door on being able to offer that service in some other way.

MR. QUINN: Okay, and that's sufficient, Mr. Stevens, and I don't want to take Julie's time here. I had questions in this area. I'll loop back on some follow-up questions, but that's sufficient for this point. Thank you.

MS. GIRVAN: Okay, and just one last question. Can you explain the extent to which Enbridge is working with Union Gas on these initiatives?

MR. McGILL: I would say it's on a very limited basis. I think they're aware of what we are doing. I'm not aware of any proposals comparable to this that they have on the table at this point in time.

MS. GIRVAN: So it's not the intent to have this type of thing through a merged company?

MR. McGILL: It may be. It will depend on what that merged company or integrated company looks like after that process is complete.

MS. GIRIDHAR: To be clear, this is an area that, you know, like others where there was not been any detailed discussions or planning on this issue.

MS. GIRVAN: Okay, all right. Thank you.

EXAMINATION BY MR. YAUCH:

MR. YAUCH: Good afternoon. I have very few questions; a lot of them have been asked and answered.

If we could go to Board Staff number 1. In part A, response A, part 3, you sort of lay out why you should be allowed to do this, and two of the reasons are it won't affect market competition and you won't have a monopoly on this business.

I heard you earlier speak about your weighting cost of capital, in fact, because you are a regulated utility and it is a bit lower than if this was in non regulated business.

Well, does that not act as a little bit of a competitive advantage to you if you are entering into this market compared to other companies, the fact that you can use your regulated cost of capital which is lower than a non-regulated company?

MR. McGILL: Well, I think it comes down to the cost of capital that our company is willing to accept. So if our parent is willing to invest funds in the regulated business that offers an OEB-approved rate of return on equity, then that's the choice of our parent.

If a competitor wanted to make comparable investments in the same kind of facilities and earn a comparable return, then that would be up to them to decide what return they require in order to go ahead with that investment.

MR. YAUCH: This being a new industry, as you admit in that answer, there isn't really any other regulated utility that would get in this space. There would be start-up companies; it's a new industry, a new company, and they wouldn't have access to the same type of cost of capital that you would you have, correct?

MR. McGILL: Well, again I think it comes -- from a competitive standpoint, it comes down to what level of return a competitor would see as acceptable.

So in our case, our parent company is willing to continue to invest in the utility and earn the utility's regulated rate of return. That rate of return might not be satisfactory to other parties, so they might require a higher rate of return or choose not to enter into this business.

But in terms of competition, I think we're all on equal ground here in terms of, you know, this is what the returns that our company is willing to accept and then it's up to others to decide whether or not, you know, they can offer the service at the same cost.

MR. YAUCH: Okay. As part of your application, there is a PI of 1.1. So the way I interpret that is ultimately current ratepayers benefit just a little bit, that .1 higher, correct?

MR. McGILL: Correct.

MR. YAUCH: If you ran it through a non-regulated business, so an a affiliate, that 0.1 would flow to your shareholders as opposed to ratepayers, right? There would be a advantage to a utility to doing in that manner?

MR. McGILL: If it was all things equal in terms of the two businesses, and the way they are funded, and the cost structures and whatnot, yes.

But, you know, I can speak from my own experience in competitive business, that competitors don't always make money; they sometimes enter markets at a loss. You know, I'm very familiar with running retail businesses, so when we put things on sale at 50 or 70 percent off, the people that bought those items at 100 percent of the original price are subsidizing the people that bought the sale items later on.

So it's very hard, when you go into a competitive world, to compare that to what we do here in a utility. There's different motivators behind what you do in competition.

MR. YAUCH: Organizationally, we looked at it. We sort of said, well, if there's no advantage to you being a regulated utility doing this, or you're not going to have any impact on competition in it, but yet if you did do it in a non-regulated environment, you'd actually have a potential to earn higher income for your parent company.

We sort of wondered why wouldn't you do it through an affiliated company. If everything else is equal, why wouldn't you try to get that benefit to Enbridge, rather than try to run it through to ratepayers?

MR. McGILL: Well, I think we see this as an appropriate utility activity. I think that's the main reason and, you know, we are well-positioned to offer this service. I think if others outside of the regulated utility industry were to offer this service, it would look very different, you know, because they would have different motivations with respect to why they're entering this line of business. It might be commodity-driven, have all kinds of different objectives associated with it.

So as I said earlier, right now we are not aware of anyone who is offering this service, you know, on a similar basis to the way we're proposing to do it. There are some people that will go out and build facilities for a client that will take those over and run them and operate them themselves. I think there's others from a standpoint of a commodity markets that might approach, you know, these kinds of opportunities in a very different way than the way we're looking at it.

MR. YAUCH: Your motivation, if I -- I don't mean to put words in your mouth. But your motivation is that this is an appropriate utility business model and that's why you're doing it?

MR. McGILL: Yes.

MR. YAUCH: If we could go to Energy Probe number 2, please. So first off, I've read a lot of IR responses in my life. I don't think they've ever been as thorough as this one.

I just have two questions on it. The bottom of the second paragraph to response A, you said:

"Enbridge requests the opportunity to make further submissions about this topic before the Board makes any preliminary or final determination on any associated issues."

Is Enbridge planning on providing more evidence or -- I didn't really understand that comment. Is there more to come, or is this...

MR. STEVENS: I think what we were signalling is that -- as you point out, Brady, this is a pretty comprehensive answer and we didn't want the Board to think, though, that this is the sum total of any legal argument that we might make if the Board decided that this was a specific discrete issue that needs to be dealt with.

So we have no present intention to supplement this answer, but there may be more that we have to say if this became an issue out at a hearing.

MR. YAUCH: The legality of -- or the Board's mandate in relation to this program?

MR. STEVENS: Exactly.

MR. YAUCH: Okay. Can I ask -- my last question is in the final paragraph -- the second to final paragraph, you say:

"Finally, Enbridge asserts that even if the Board should find that it does not have the express jurisdiction to permits, including this," blah, blah, blah, "...it should be permitted on the doctrine of necessary implication."

So am I right to interpret that even if you don't think the Board has a mandate -- if it doesn't believe it has a mandate, you believe that the Board has a mandate?

MR. STEVENS: I think what we were intending to signal by pointing to the doctrine of necessary implication is that if the Board were to determine that the specific words of the statute do not support these activities, there's still a second argument to be made that a broader interpretation of the statute has to be made to allow such activities, because that's the way that the Board can in fact actuate or bring into practice its statutory aims and the policy expectations of the government.

MR. YAUCH: All right. Those are my questions. Thank you very much.

MR. QUINN: Yes, thank you and I might -- let's put it this way. I appreciate the panel's answers today. Some of my questions have been answered, but it's created more questions. So if this doesn't flow well, I apologize up front.

I'm going to start where Brady left off. This is in Energy Probe number 2 and I was kind of surprised to read, just further down in that, it says -- on page 2, the second full paragraph -- sorry, third full paragraph, the part that is italicized is:

> "The Board's statement that responsibility of GHG emissions-related gas delivery is an ongoing business obligation of a natural-gas distributor under the Climate Change Act part of the utility's cost of providing distribution service similar to other delivery costs."

Now, that is -- and I was obviously quoted -- is from the Board's determination, but is it not true that Enbridge did not support that approach in that same proceeding?

MR. STEVENS: I mean, Enbridge may have taken different positions, but Enbridge certainly accepts and governs itself in accordance with the decisions that are ultimately made.

MR. QUINN: But -- and thank you, Mr. Stevens. I understand that. But if changes in government and government policy and potentially climate change acts are made, if this is the premise for this service is that because it's part of the ongoing responsibility of a distribution service, like other delivery costs, if this is the premise to say therefore it must be a utility service and is a part of our doing business, do we not lose that? Like, without that reason for being, which may or may not change in the future, we have a 20-year -- you are entering into 20-year agreements that might live beyond those -- those words?

MR. STEVENS: I think it's fair to say, Dwayne, that where there's specific reliance in the application on specific policies and legislation and then subsequently those policies or legislation change, then they can't -- it's fair to say that that's no longer something that can be relied upon.

That said, I think at a higher level, as the witnesses explained from the beginning today, that there continues to be, as far as we're aware, a governmental interest and imperative in reducing emissions regardless of cost of carbon questions, and the RNG program is designed to enable the growth of an RNG market that's going to help support those aims being realized.

MR. QUINN: Okay, and I know we don't want to maybe deal too much in the hypothetical, but maybe the specific question is: Is Enbridge relying on that statement to say ergo we need to have a rate that is a distribution rate for our service?

MR. McGILL: Well, I think, you know, some of the points we've been trying to make today is that regardless of what happens with respect to carbon pricing in the province of Ontario, there is still a demand for these services in the market we serve and that we believe that we are in a good position to meet that demand and that we brought forward, you know, a reasonable and well thought out proposal which -- in terms of how we intend to meet that demand for these services, so I think that with respect to RNG, as I said earlier, I think the model stands up on its own. As long as there's parties out there that are willing to contract for these services, then I think we should be in a position to provide them.

MR. QUINN: Okay, thank you.

Earlier today we had -- there was a -- we've had discussions with a number of parties regarding the -- specifically the upgrading service, so separating it out and saying we are just talking about the upgrading service, and at different times you've talked about companies, including potentially an affiliate of yours, looking for a, potentially, a higher rate of return, so if -- again, I don't want to put words in your mouth, but Enbridge Inc. were to do this, they might be seeking a higher rate of return; is that correct?

MR. McGILL: They may, depending on what other initiatives an RNG upgrading initiative would be competing with.

MR. QUINN: Okay.

MR. McGILL: So, you know, they're looking at other projects across North America or actually worldwide and, you know -- so it would depend on, you know, how the viability of an RNG upgrading project compared to whatever's on the menu at any point in time.

MR. QUINN: So that's a competition internally for capital, internal --

MR. McGILL: If we are talking about an Enbridge affiliate, that is the kind of competition for --

MR. QUINN: Right.

MR. McGILL: -- capital it would face.

MR. QUINN: Right, and so if another party -- and you started down this road just a short while ago, Mr. McGill, in terms of why parties might enter this space to compete for it, and they may or may not, I think was your outcome of what you were saying, they may or may not seek a higher rate of return depending on what their reasons are for entering the market?

MR. McGILL: Yes.

MR. QUINN: Okay, now, when you're talking with Mr. Vellone this morning, you were talking about the co-locating of those facilities, and from an engineering perspective that makes a lot of sense. You know, you've got opportunity, and you may have telemetry and other things that it's easier to have the two together.

But does that not give Enbridge a competitive advantage, a sustainable competitive advantage, over any other competitor to say, we're going to likely have these upgrading and injection facilities co-located so, as you said yourself, it's going to lower our cost for doing that? Does that not give you a sustainable competitive advantage over another provider?

MR. McGILL: Well, not necessarily. So the upgrading facility is discrete from the injection facility, so I don't see there's any reason why, you know, a third party couldn't come in and provide the upgrading facility and operate it on behalf of a client and then the upgraded gas passes into our injection facility and then goes on into the gas distribution system.

So, you know, there may be some savings in terms of building these things on an integrated basis, but we would be working with our customer to do that anyway. You know, you can't just work in isolation when you are trying to build an integrated facility.

MR. QUINN: I guess I have an appreciation for that, but from my experience, having one contractor on-site doing two facilities and the facilities are similar valves and the valves go together the same way with the pipe, that, in and of itself, is going to give an opportunity to lower the cost of the two facilities or, in this case here, half of the facility.

MR. McGILL: It may, but again, like, we have to work with the customer, and the customer's not going to go ahead with the project on any basis if it can't be made to work in an economic way, so I think there's elements in the process of negotiating arrangements with the customer that would dictate that these things are built in a cost-effective way.

So like I said earlier, there may be some advantages of building these things in a more integrated way, but I don't see that as being significant advantage that we would have.

MR. QUINN: Okay. We may disagree at some point, but I'm going to move on. If you establish that the customer is going to move forward if it's economic, and we may or may not agree whether you could do it more economically than company X, Y, Z, but to the extent there is really or perceived benefit from dealing with one party as opposed to two parties, one for upgrading, one for injection, isn't there a risk that while you are trying to spur a market you are actually inhibiting the market development because of the -- how you are rolling the system out?

MR. McGILL: Just give us a moment, please.

[Witness panel confers]

MS. GIRIDHAR: I don't think that's true, Mr. Quinn, just based on the experience we had. Now, I can't say too much about the RFP that we held recently, but we got some very good responses, and some of those responses wanted to take the upgrading service from us and others did not. So, you know, we went through the process of providing costs, and they presumably could have compared that with whatever it is that they were coming up with, and a number of them were not interested in the upgrading service, so I -- as Mr. McGill explained, I think it really depends, you know -- largely we think municipalities like the notion of getting an upgrading service from us because they like that we take care of it, you know, and as a public utility that's regulated, there is transparency around the costs, it fits with their, you know, their model that the transparency that we provide. There are other private operators that might just be interested in taking an injection service from us. We don't believe it hampers the market in any way. It facilitates the market. It's an enabling service and it's been specifically designed to enable the market.

MR. QUINN: Okay, and I appreciate your answer. And again, we may or may not see it the same way, but I'm going to ask one more question in this area.

How the service is costed can have a big implication and when Mr. McGill was talking about the retail market, for some of our -- some people in this room had careers that spanned the days of rental water heaters. And to the extent that there's costs allocated differently, whether the service is part of the utility or not part of the utility, that can make a big difference in terms of the value or the price to the customer.

So my question specifically is how is Enbridge going to assure the Board that there is a proper allocation of these respective costs, such that the upgrading service isn't somewhat subsidized by the higher cost of the monopoly-required service, the 401 service?

MR. McGILL: Well, I think -- you know, I think the comfort around the way the costs are allocated comes from the way these contracts will be negotiated. So they'll be negotiated with the customer.

They will all an site-specific. They will all have different costs. We will be breaking out the cost of the upgrading component and the injection component separately. So there is going to be a full view to what those -- what the rates for each of those two services are covering in terms of cost recovery.

So that's all broken down and, as Malini said, it is a very transparent process. It is a cost of service calculation, so that, you know, our customer can see exactly what's going into it in terms of capital cost, operating cost, our returns, et cetera.

So the whole process is transparent from the customer's standpoint, and I think that should satisfy any concerns as to how we're allocating costs to these things.

MR. QUINN: Would the Board see those costs. You mentioned earlier that a number of these would have a leave to construct. It would only be when there is a pipeline added and it creates a leave to construct, will the Board see these costs?

MR. McGILL: Well, they certainly would in the situations where there's leave to construct. You know in terms of the application of the -- so the guidelines around when a leave to construct is required, I think the capital cost of these facilities would, in most cases, require some form of leave to construct application. So I think the Board would see most of that.

It's hard for me to imagine situations where they wouldn't. And I think, in any case, the Board would always have the authority to look at what we're doing and understand the cost associated with these services, in any case.

MR. MONDROW: Dwayne, if you are going to leave this topic --

MR. QUINN: I was about to, Ian. Go ahead, proceed.

MR. MONDROW: Just while we're on it, Steve, you don't need a leave to construct for the upgrading facilities that you are proposing?

MR. McGILL: Well, I think that's something we haven't really decided as of yet.

I'm trying to think of the -- there's the four criteria for a leave to construct and one is the pipe size, one is the capital cost is 2 million, one is the operating pressure and there's four -- the length of the pipe.

So I think where we could find ourselves having to go to a leave to construct on these things is on that $2 million cost item.

MR. MONDROW: All right. And in the leave to construct then, do you intend to present evidence of how overheads, utility overheads are allocated into the price that -- or the rate that you are recovering, or propose to recover from the customer?

MR. McGILL: Well, I think we would be showing the costs that are allocated to the project, yes. So, you know, in terms of the degree of detail in terms of how we go through the cost allocation process, that's something we do as a regular part of our business today with respect to costing affiliate transactions, or things of that nature, and we have processes in place to determine those allocable costs that are consistent with the Affiliate Relationship Code.

So we would be using that is the guideline on which we would allocate costs to these projects.

MR. MONDROW: That's fair enough. When you answered Dwayne's questions, you talked about transparency to your rate 400 or rate 401 customers.

The issue that some of us are concerned about, I think -- and I think the Board would be concerned about is the avoidance of a subsidy from ratepayers. And it's the Board on behalf of ratepayers that would need to see you are recovering all the costs related to that activity from the customers of that activity.

You would be prepared to demonstrate that in these proceedings, presumably.

MR. McGILL: Yes, we would.

MR. MONDROW: Okay, thanks.

MR. QUINN: I will move to a slightly different topic. We were talking about Hamilton earlier and I think it might have been said, but my understanding is that Hamilton uses a lot of its production of renewable natural gas for cogeneration and on-site usage. Is that your understanding?

MR. CHAGANI: I don't think that's my understanding. My understanding was that they used a lot of their raw biogas for cogeneration than, or for -- I think they have a bio fit contract or something along those lines -- and then the excess is turned into RNG and brought to market.

MR. QUINN: That's said better than I did, and thank you. So they're using the raw biogas, but obviously the injection facility we're talking about -- that's Union's facility that would be comparable to your injection type of facility. But that upgrading; is the upgrading required for them to use that biogas for their own usage?

MR. CHAGANI: I'm not familiar with the way -- like, what the processing of the biogas is. But from my understanding, if it's a wastewater treatment plant, there would be some level of -- I guess...

MR. QUINN: Cleaning?

MR. CHAGANI: Well, it's not really cleaning. There is a preparation step before you can push it towards the on-site generator.

MR. QUINN: Okay. So you are not that familiar with it then?

MR. McGILL: I think, just to be clear, it would depend on what the city wants to use the product they're producing for.

MR. QUINN: Um-hmm.

MR. McGILL: So if they are using the raw biogas to meet their requirements under, you know, a FIT contract, then that gas would require little upgrading in order to be used in a generator to satisfy those needs.

But let's say they wanted to take the excess biogas, convert it into pipeline quality RNG to fuel -- to provide as a heating fuel to another building in the city, then it would have to go through the upgrading and injection processes as we've described earlier.

So I think it's up to, in that case, that customer of Union to decide, you know, what they want to do with the gas and how they optimize that operation for their own benefit.

MR. QUINN: It would come down then to the economics of they've got a potential feedstock and do they use it themselves, do they refine it for distribution utilization for themselves or for somebody else?

MR. McGILL: Yes.

MS. GIRIDHAR: And I understand that Hamilton also has RNG for its transit, some of their buses, the Hamilton Street Railway, I think they call it.

MR. QUINN: But is it your understanding that they are using gas that they have injected into Union Gas' system for the purposes of those buses?

MS. GIRIDHAR: I don't know that. I just know that they produce RNG and they also have CNG buses.

MR. QUINN: Okay. And looking at this from the why would we do it and the spurring of the market, you've got an organization -- and Ms. DeMarco went through this with you this morning -- in separating who's getting the benefits.

You're getting -- the term that was used was substitution benefit. The producer is getting the opportunity for an offset benefit.

MR. McGILL: Right.

MR. QUINN: So that would reside in the -- in this case here, I'll stay with the municipality. I won't use Hamilton per se, but let's say it's a municipality in that system.

They're getting an offset benefit based upon -- based upon a capturing of potentially fugitive methane that is not either going into the environment or having to be flared; is that your understanding?

MR. McGILL: Yes, that's part of what creates that value.

MR. QUINN: So Enbridge would potentially -- and I won't say lose out on, but you would not get the substitution benefit unless that was injected into your system.

MR. McGILL: Yes, in order to get the substitution Benefit, the gas has to be injected into our gas distribution system.

MR. QUINN: Right, so there has to be a value proposition that would say what the incremental cost of upgrading -- whatever incremental upgrading is necessary and the injection to cover the value of your substitution benefit.

MR. McGILL: Well, I think -- you know, as we talked about earlier, there is different categories of those benefits, so there's the direct substitution benefit and then there's the benefit that would come from generating offsets or RINs or other carbon abatement instruments, let's call them, and those would rest with that RNG or the biogas producer.

MR. QUINN: Right. And so I was struggling with this, and Mr. Mandyam just left, but I was asking him for a reference of what the cost is, you know, in terms of abatement opportunity that is associated with, you know, that -- the substitution benefit, and the best -- I couldn't find it in your evidence, so the best evidence we had was actually out of their most recent carbon cap proceeding, and it was a Union Gas undertaking, so I'm just using these numbers for illustrative; I'm not asking you to even accept them subject to check, but in JT1.25, which I forwarded to Bonnie, to Mr. Mandyam, to Joel here also, there is a table which we asked unit break out, based upon the assumption -- and it's up above there -- sorry, Ms. Adams -- this is all based upon $16 a gJ, which was thrown out in the carbon cap proceeding, to say, okay, so what is the cost of this abatement relative to a purchase price, assuming a $16 per gJ RNG cost?

So using these numbers, again, to be somewhat in the ballpark, if it's $16 is the number, as an abatement cost in year 1 -- and just focusing on year 1 for the moment, because it is illustrative, but the compliance cost, without government funding, that compliance cost would be $240 per tonne. Do you see that there at the line E?

MR. McGILL: Yes, I see that.

MR. QUINN: Okay. So I'm trying to understand, has Enbridge analyzed this opportunity that you are getting the substitution benefit and what the relative cost of the incremental facilities for a wastewater treatment plant to inject in your system, what are they -- they are getting the opportunity to inject into the system; you are getting a potential offset, but the offset cost looks like it's in the order of $240 per tonne, and that -- when we don't have the marginal cost curve and that's not what this proceeding is about, but that's a relatively high cost even in comparison to the current cost of carbon in Ontario today.

So I'm just trying to understand the analysis that's gone into the value proposition of moving gas into your distribution system for, in this case, marginal benefit, at what would likely be a substantive cost?

MR. McGILL: But that is not a cost for the company, so that substitution benefit, that's derived as a result of the GHG reporting requirements we operate under which dictate the number of carbon allowances we have to buy, so that benefit accrues to our ratepayers regardless of what this production cost of the RNG is.

So in order -- you know, if the $240 a tonne -- and I don't know if that's equating to the $16 a gJ they reference in the other part of the interrogatory response -- then if somebody is willing to pay the $16 per gJ for the RNG anywhere in North America, then you've got a business model that makes sense.

And so when we went through our procurement model we said, well, if we pay $16 per gJ for RNG, that's going to mean our gas costs are going to increase to the extent we bring RNG into the system, say, call it by $10 a gJ compared to what it might be today.

We said, well, that's not going to be acceptable, so we went to the government and we sought GreenON subsidy money to basically make up that $10 difference in terms of ballpark numbers, so that was what that model was premised on, but to come back to my earlier point, that as long as someone in this -- like, under this example is willing to pay that $16 a gJ for the RNG, the RNG producer has a business.

MR. QUINN: Okay.

MR. McGILL: And that might not necessarily be Enbridge Gas Distribution paying $16 a gJ for it.

MR. QUINN: I am trying to follow the questions that you are creating in your response, so I'll do them reverse chronological.

If it's not a purchase -- if they can't find a buyer at $16 a gJ because that is simply put out of the market for what natural gas is these days, then they -- their value propositions which they're going to have to do their own economics on is going to have to say if I can't find a buyer for that then I'm going to have to use it myself as potential.

So is Enbridge using some of its knowledge capabilities or technology to assist customers in doing this analysis of what their costs are for using it themselves versus finding a way to get it into the pipeline?

MR. McGILL: Well, I think in terms of consulting with a customer, we might have some discussions with them along that line.

So if you had a -- say if it's a municipality and -- city of Toronto, they probably have 500, a thousand building sites across the city where they could use the gas, so we would have discussions about -- with them potentially to say, well, okay, if you're not going to sell that RNG in the market or strip off the offsets, et cetera, and sell those separately in the market, you know, so how could we help you get that gas to those locations, we could enter into that gas transportation agreements or figure out a way to supplement existing gas distribution or transportation agreements, they introduce that supply to help them make it work.

MR. QUINN: But you're --

MR. McGILL: They're not consulting with customers as to the economics of their RNG business.

MR. QUINN: Fair enough, so I'll leave that line, because I wasn't asking if you could help them get it to their other sites, I understand that, but using it on their own site, reducing the amount of investment, that's going to be their decision.

The other part you said before was, so, you know, you didn't want to take it into your portfolio at $16 a gJ, and we're thankful for that, but you said -- but you sought the GreenON money to reduce the impact on customers, but would you agree with me that those same customers are paying for carbon cap costs which fund the GreenON funds?

MR. McGILL: Well, the way I looked at that part of the situation was is that that hundred million dollars was a vehicle to return some of the money they had paid towards carbon allowances through their gas bills.

So to me I saw that as a real benefit to our customers that, here, you're getting at least 100 million back, or between us and Union $100 million back of the money that you've paid for carbon allowances through paying your gas bill, so I thought that was a positive thing.

MR. QUINN: And I don't want to get into the compliance debate. I think this would end up being argumentative. I'm just -- when I look at the $240 that's here as compliance cost without government funding, that is a significant cost relative to other options on your marginal abatement cost curve, correct?

MR. McGILL: Right, but this isn't an option that we are pursuing in terms of meeting our carbon abatement goals.

MR. QUINN: Okay. Well, I guess I --

MR. McGILL: So if it's someone in California is willing to pay the $240.67 tonne-equivalent, then there is an opportunity for somebody to produce that RNG in Ontario and sell it to them and potentially make money on it.

MS. GIRIDHAR: So maybe I can just provide a little bit more perspective as well, you know. I guess it's not for us to figure out what are the motivations of somebody willing to pay $16 per gigajoule for a fuel that they could procure at $3 or $4 or $6 per gigajoule.

Presumably the carbon abating value is significant enough that they want to pay $16 per gigajoule, but I just wanted to -- you know, if you are an entity that wants to abate carbon and you don't look at RNG, you would be looking at renewable electricity in today's world, because those are the two alternatives you would have in front of you.

So natural gas, pure natural gas, is landed at something like 3 cents per kilowatt hour. Electricity in Ontario is 12 cents per kilowatt hour. The reality is, even if you paid $16 per gigajoule for RNG, it would be a lot cheaper than renewable electricity in your portfolio.

So I think it is not for us to judge people on their carbon abatement decisions, but if parties want to abate carbon and are looking for cost-effective solutions and want to procure it at $16 per gigajoule, then I think we're in the business of helping them do that. And we also know it makes sense relative to other alternatives they are facing.

It is certainly cheaper with full-scale electrification with renewable energy, if that's what the entity is looking to do. So for a number of reasons -- and plus, of course, you also get storability with this product that's $15 or $16 a gigajoule. It can be stored year-round, it can be stored seasonally; that is not the case with renewable electricity.

For a number of reasons, RNG makes sense, our customers are telling us it makes sense, and just the physics and economics of energy distribution in Ontario tells us it makes sense.

MS. DeMARCO: I wonder if I could help, because I think there is confusion as to what you're paying for and proposing and what you're not.

So in relation to the direct emission reductions, i.e. the RNG itself, if you could possibly explain what you intend to do there versus the substitution emission reductions and how you calculate that on the basis of avoided compliance costs.

MS. GIRIDHAR: There is no carbon costs included that are being paid for by our ratepayers in any of this, unless we have an RNG procurement plan that is paid for ratepayers.

That is not the proposal in front of you. What is in front of you is an RNG enabling program where we charge any project proponent who wants to take the service from us the full cost of taking the service over the life of the contract that they have with us. And we have an inter-temporal debit or credit, depending on what the revenue requirement is relative to that levelized cost.

Anything else that we do on top of that is not the subject of this proceeding.

MR. QUINN: Do you have anymore questions?

MS. DeMARCO: No.

MR. QUINN: We're not going to go any further. I wasn't going to bring up renewable electric, but...

MS. GIRIDHAR: Well, no, you were wondering what the $16 is and the 200 and whatever -- $223, $240 per done. Like I mean that's what it is. I mean, people have to understand what is their cost of abating carbon, so I'm just trying to explain what might prompt somebody to pay $240 per ton by using RNG. They would do it because their next best alternative is more than $240 per ton.

MR. QUINN: In Hamilton's case -- and I haven't studied it completely and it's not on the record here, but they have been doing it a number of years and generating their own electricity renewably.

But they are using that biogas differently and with less -- as I'm understanding -- less of a need to have the upgrade/injection facilities.

So that put aside, I'm going to focus back and use the word "facilities" because there's something that was said earlier about the life of these facilities is 20 years.

I'm struggling with that, having designed and built stations before, those -- the valves -- the meters may have to be switched out after 20 years, but the valves, the filters, the main piping, in your own metering stations for your customers, they are given a lot longer life.

Why are the systems that are being put in place for RNG service having a substantially shorter life?

MR. CHAGANI: So what Steve was referring to earlier is the actual upgrading sites. So the upgrading sites, from our discussions with manufacturers, is that they have a life of 20 years.

Now, the second piece is the injection site and you're saying, well, why are you also mirroring the injection site with 20 years? Steve also mentioned that the EBO 188 for industrial customers has a maximum feasibility period of 20 years, so we are using that same framework. So we should therefore use the same feasibility timeline.

So even though an industrial customer -- yes, you're right, the meter may last longer than 20 years. When we run the feasibility, we use a maximum of 20 years.

MR. QUINN: Okay. So it's not the service life of the equipment in your injection facility?

MS. GIRIDHAR: Economic life.

MR. McGILL: I think it happens to be a coincidence that the physical life of the upgrading facility equals 20 years, which is the maximum feasibility period that we have in EBO 188 for an industrial customer feasibility test.

MR. QUINN: Well, maybe I misunderstood your answer Before. I thought you were taking about the service life, and it may have only been pertinent to your upgrading facilities. So that's better clarity now, thank you.

I'm watching the time here, so I'm just going to move to FRPO.5.

MR. RUBENSTEIN: Could I ask a follow-up?

MR. QUINN: Yes, sorry. Go ahead.

MR. RUBENSTEIN: Dwayne was asking about the length of time in the life of the asset.

MR. McGILL: Yes.

MR. RUBENSTEIN: So say you enter into a 20 year -- the normal depreciation time for the assets is, say, 40 years, just as an example. And the contract length is going to be different than necessarily the depreciation time.

Are you then going to depreciate these specific assets to match the contract length, or are you just going to depreciate them as they normally would?

MR. McGILL: We will set the depreciation rate to match the contract life.

MR. RUBENSTEIN: Okay. So that means you will have to segregate in your depreciation schedules each individual customer's assets in their contract?

MR. McGILL: Yes.

MR. QUINN: On FRPO 5 -- and again, earlier we separated this idea of offset benefit versus substitution benefit. And so the response that was heard in context earlier was that this guideline for quantification reporting of greenhouse gas emissions, the Ontario regulation 400, that is quantifying the substitution benefit; is that correct?

MR. McGILL: Well, it's the regulation that, I guess, supports the substitution benefit is, you know, the best way I can describe it.

It's the reporting regulation that supports the substitution benefit.

MR. QUINN: And you're familiar with it because it is attached to the original undertaking here that Union had offered some support for that view from the inter-governmental panel on climate change? It was attached to the original interrogatory. The reference is the AG Exhibit JT124.

[Witness panel confers]

MR. McGILL: I don't have the reference that you are referring to here.

MR. QUINN: I want to be fair to the panel, and I thought you might have had that because it was specific and was used in the carbon cap compliance proceeding.

But the premise that Union had pointed out was that biomass was -- combustion biomass was considered carbon neutral because the biomass re-grows.

And our question has been and continues to be: How does that work for a wastewater facility in a municipality?

MR. McGILL: Typically in a wastewater facility, the methane that is produced as a result of treating the wastewater would typically be captured and, in most cases, flared. So you are destroying the methane by flaring it and, as a result of that, you are emitting CO2 into the atmosphere.

If you capture that methane and upgrade it into RNG you're, one, avoiding having to flare that gas and turning it into a useful product.

So in terms of the reporting regulation, when it was derived, the province determined that when we report our RNG -- or pardon me, GHG emissions that result in our allowance requirement, it is reduced by that amount of RNG or renewable fuel that we bring into the system.

So basically it comes down to just the way the regulation is written.

In terms of establishing what the offset value is for RNG, it would differ, based on different sources of feedstock.

So something like agricultural waste, where the methane is venting directly into the atmosphere and it is typically not captured and destroyed, RNG derived from that kind of feedstock would have a higher offset value than RNG, let's say, derived from a landfill site --

MR. QUINN: Because you are talking about fugitive emissions and the impact of methane being higher than carbon, so your prime premise then on the wastewater treatment plant is the presumption that it is all flared.

MR. McGILL: Okay. So it would vary from one wastewater treatment to another. Some have open lagoons where the methane is just going straight into the atmosphere. If you were to capture that, I would suggest that would create a higher offset value than a situation where the methane is being flared today, and that would vary from site to site.

MR. QUINN: So it is going to vary from site to site, but in the case of Hamilton, as an example, a municipality that's going to benefit from RNG, they can do things on-site to increase the amount of methane that they can extract from their plants; correct? So --

MR. McGILL: Yes, to some extent, yes.

MR. QUINN: Okay. So I understand your premise now. It is helpful to hear that answer on the basis of flaring for the first time, but I guess my concern is more broad than just your application, it is the regulations, and we'll have to take that in a different venue, so I'm satisfied with your answer, Mr. McGill. I will just take it as that for now and move on so others can have some time.

MR. McGILL: Okay, thank you.

MR. QUINN: Thank you.

MR. MURRAY: Mr. Mondrow, would it be good for you to go now, or a break, I think.

MR. MONDROW: I'm happy with a break.

MR. MURRAY: Are you ready to go?

MR. MONDROW: Yes.

MR. MURRAY: Okay. Let's go ahead. Let's try and get through one more. Do you guys need a break? Do you guys want to take a break?

MS. GIRIDHAR: No, we'd like to get through it.

[Laughter]

MR. STEVENS: The question is whether we can get through Mr. Mondrow and whether both Ian and Mark can get done in time now if everybody can survive without a break. If we're going to take a break anyway now is a good time.

MR. MONDROW: I don't know. I'm not going to promise.

MR. STEVENS: Are you --

MR. MONDROW: I'm more than five minutes, less than an hour. I put down 30 minutes.

MR. STEVENS: Between the two of you I think you've got almost an hour.

MR. MURRAY: I guess the question is over and under. Are you expecting to be here 30 minutes --

MR. MONDROW: Why don't we just take a five- or ten-minute break. I don't know. I mean, I had a brilliant series of questions this morning. It is a little foggier now. So I really can't -- sorry. I am going to be 20 to 30 minutes, I think, is my guess or --

EXAMINATION BY MR. MONDROW:

We'll go with the court reporter's preferences. Let's go 'til 3:30.

All right. Let me start with something -- I think you said -- one of you said off the top -- you said absent the cap-and-trade framework Enbridge Gas Distribution will seek a variance account. And my question is to capture what?

MR. McGILL: It would be to capture the revenue deficiencies and sufficiencies over the life of these contracts.

MR. MONDROW: Okay, and how is that different from what you're proposing to do with the cap-and-trade framework in place?

MR. McGILL: Well, the only real difference is that under the cap-and-trade framework we have an existing customer GHG variance account.

MR. MONDROW: Okay.

MR. McGILL: So these deficiencies and sufficiencies would probably be small entries into that larger variance account where, if we lose that variance account as a result of the wind-up of cap-and-trade, then we would seek for a -- to have a dedicated variance account with respect to this program set-up.

MR. MONDROW: Okay, thanks.

Earlier, Steve, I think I asked you whether the benefit of the avoided carbon compliance costs in respect of RNG applies whether or not the RNG is consumed in the province or out of the province, and your answer was it doesn't matter whether it's consumed in the province or out of the province.

MR. McGILL: With respect to that substitution value that's derived as through the GHG reporting requirements we operate under.

MR. MONDROW: Okay, and I wonder if you could simply, by way of undertaking, provide the specific reporting regulation provision that makes that clear.

MR. McGILL: Yes, yes, we can do that.

MR. MONDROW: Okay. Thank you.

MR. MURRAY: That will be Undertaking JT1.14.
MR. McGILL: We may already have that in an earlier undertaking, but --
MR. MONDROW: Okay.
MR. McGILL: -- one way or another we can --
MR. CHAGANI: It's within -- it's one of the requirements of JT1.2 already.
MR. MURRAY: Okay, then we will remove that undertaking. It will be included as part of JT1.2.
MR. MONDROW: Okay, thanks.
Malini, I think you've said this a couple of times, but we all agree, I believe, that the -- well, let me back up. You've referred to a nascent market, I think you referred to that in an undertaking -- at least one -- sorry, at least one interrogatory response, probably more -- I think you referred to it this morning. What market are we talking about? Are we talking about an RNG market or are we talking about an upgrading services market?
MS. GIRIDHAR: I think they're both nascent.
MR. MONDROW: Okay. And is the nascency of the upgraded services market one of the rationales that you offer for the appropriateness of EGD providing the service you requested approval for?
[Witness panel confers]
MS. GIRIDHAR: No. I mean, we are calling it an RNG enabling program, so we believe it's helpful to the market. It helps bring more RNG into the market. The construct, as

well, though, is there's an optional service, so to the extent that an RNG producer is motivated to bring RNG as a result of the service, that's great. If they feel they could do it without the service, that's fine too.

MR. MONDROW: Okay. And it helps bring more RNG into the market, I think you said, because -- Steve said this this morning -- you can do it at a lower cost than others can do it, you believe?

MS. GIRIDHAR: To be clear, you know, we don't believe that there are competitors at this point.

MR. MONDROW: We'll get to that, but you did say you have a lower cost of capital and that's an advantage in terms of facilitating this market?

MS. GIRIDHAR: We believe that for Enbridge to facilitate this market it makes sense to do it as a regulated activity because we have the benefit of a lower cost of capital --

MR. MONDROW: Okay. And --

MS. GIRIDHAR: -- than outside of regulation.

MR. MONDROW: Right. And Steve, you talked earlier with others about the level of return required. And it's up to a provider of the service to determine what level of return they want in offering the service. People are free to pick a level of return.

But it's true, isn't it, that EGD has a lower cost of capital and a lower return on equity because it's got a lower risk than a non-regulated company, and it's got a lower risk because it's regulated.

MR. McGILL: I think that's the standard thinking, that --

MR. MONDROW: Might not feel that way sometimes, but...

MR. McGILL: That utilities, regulated utilities, typically face lower risk than competitive business and that, you know, that's probably the case.

MR. MONDROW: In the Enbridge group the return required by your shareholder from the utility is lower than the return required by your shareholder from unregulated activities; right?

MS. GIRIDHAR: Correct.

MR. McGILL: For the most part, yes.

MR. MONDROW: And what's the spread, do you know?

MR. McGILL: It would vary from one initiative to the next based on the assessment of risk associated with each of those initiatives.

MR. MONDROW: Is it true that the cost of the utility's debt is lower than the cost of debt for Enbridge's unregulated businesses generally?

MR. McGILL: I'm not sure with respect to the cost of debt because we have our own debt issues and I'm not sure how that would compare to the overall level or the cost of debt that Enbridge Inc. incurs at a corporate level.

MR. MONDROW: You are not sure --

MS. GIRIDHAR: We rely on the expertise of our treasury group. We take our projects to them, as does everybody else, and then they decide what the cost of capital is for a project based on an assessment of the risks associated with the project.

MR. MONDROW: And you don't agree that historically the cost of debt for EGD is lower than the cost of debt for an unregulated Enbridge business; that has not been your experience?

MR. McGILL: There is a difference between cost of capital and cost of debt --

MR. MONDROW: I understand that. I asked you about cost of capital and the cost of debt.

MR. MONDROW: I understand that. I asked you about cost of capital, and now I'm asking...

MR. McGILL: In terms of cost of debt, I don't know because of the way the company is financed. But in terms of the cost of capital that would be required from one initiative to the next, that would be different and, you know, in my experience, that's usually driven by considerations around equity returns, not so much by a cost of debt.

MR. MONDROW: Okay, thanks. I think somewhere in the interrogatory responses you talked about the advantage of your customer relationships in making people feel comfortable with you providing an upgrading service. Is that correct?

MS. GIRIDHAR: Yes.

MR. MONDROW: And similarly, they trust your brand as one of the selling features?

MS. GIRIDHAR: Yes.

MR. MONDROW: All right. Thank you. Something that you talked about earlier was the fact that you only have one customer for whom you inject gas. We talked about that already. I interjected and asked you a question.

Union, of course, has a number producers that inject gas. Do you know if they have -- I just don't know the answer. Do they have an injection service and a dedicated rate for that, they being Union Gas?

MR. McGILL: Union Gas has a rate. It's their M13 tariff, which is a wheeling rate, just basically to move gas from point A to point B. And that's what they apply with respect to local production that -- you know, I'm not sure to what extent Union actually procures local production, but I know that they use M13 for their wheeling rate.

With respect to the facilities to take that gas into their system, I believe they charge the customers for that, like up front, in order to construct those facilities.

MR. MONDROW: Okay, thanks. We've talked about the city of Toronto a couple of times. They are the only potential customer of these services with whom you currently have an agreement in place, as I understand it. Is that correct?

MR. McGILL: That's correct.

MR. MONDROW: And I think you said earlier, Steve, that you're aware of another one or two projects, upgrading projects?

MR. McGILL: Yes, the City of Toronto has potential projects and we've had discussions with other GTA municipalities, principally Durham and Peel.

MR. MONDROW: Are they at the stage of projects, or are they just interested in the concept?

MR. McGILL: We're at the discussion phase with them.

MR. MONDROW: Early?

MR. McGILL: Yes.

MR. MONDROW: Okay. You're aware of the Niagara RNG project by the Walker environmental group landfill?

MR. McGILL: Yes, we have some knowledge of that.

MR. MONDROW: And am I correct that they are planning to self-perform the cleaning function -- sorry, the upgrading function.

MR. McGILL: I'm not sure -- they are undertaking -- they are taking on the responsibility for the upgrading function. I'm not sure exactly how they are going to go about doing that.

MR. MONDROW: Okay. Are they about shovel-ready, do you think?

MR. McGILL: I don't know. I wouldn't think that they're that close at this point in time, but I think that they're probably in design phase and trying to determine, you know, equipment providers and things of that nature.

MR. MONDROW: Do you know if they are going to use the RNG for themselves, or are they going to inject it into your system? Do you know what they plan to do with it?

MR. McGILL: I believe it's going to be injected into our system.

MR. MONDROW: There is a Storm Fisher Environmental Ltd. project near London, Ontario. Are you aware of that one?

MR. McGILL: I'm aware of that facility; that facility has been in place for some period of time.

MR. MONDROW: That facility being a landfill of some sort?

MR. McGILL: Yes, it's an anaerobic digest.

MR. MONDROW: Okay, sorry. Producing biogas?

MR. McGILL: Producing biogas, yes, and I believe they have a FITT contract for electricity production and my understanding is that they are looking at expanding that facility to add some potential to create renewable natural gas.

MR. MONDROW: Do you know if they are planning to either self-perform or assume responsibility for the upgrading function?

MR. McGILL: I don't know the details of that arrangement. That facility is in -- located in Union's service territory, so they would be having discussions with Union Gas along that line.

MR. MONDROW: Okay. That actually raises another question -- I'll come back to the other question.

So we've talked about Toronto, Niagara, Storm Fisher, some municipalities which are in discussion stages, and you've mentioned the names of those.

Are there any other projects that you're aware of for upgrading biogas to RNG?

MR. McGILL: Yes, I think there's other parties we've spoken to, apart from municipalities, that have an interest in pursuing RNG production.

MR. MONDROW: They would be also in the early -- conceptual, early stages?

MR. McGILL: Yes.

MR. MONDROW: Have any of those other projects indicated that they will do the upgrading, or could do the upgrading on their own?

MR. McGILL: I don't know that we're far enough along in those discussions. As Milani indicated earlier, through the RFP for RNG procurement, we did get a sense as to -- that some parties were interested in us performing the upgrading service for them, and some parties were interested in taking that responsibility on themselves.

So there was a bit of a mix there.

MR. MONDROW: Okay. You've said that if you perform the upgrading service -- Mr. Chagani, this might have been you -- you are actually going to procure the equipment from third parties. Is that right?

MR. CHAGANI: From the manufacturers of the equipment, yes.

MR. MONDROW: Are you going to do the construction and installation with Enbridge people, or are you going to contract that out?

MR. CHAGANI: It would probably be a combination of both, depending on what activities Enbridge would do and what activities our contractors would do. But we would be utilizing our contractors in the same fashion we do for our pipelines and we would also have on-site PSIs, which are which are inspectors. We would have our project managers, et cetera.

MR. McGILL: We would be project managing all of these projects.

MR. MONDROW: And the engineering work, you said, I think, you would go to outside engineers experienced in these facilities?

MR. McGILL: And they're working with our own internal engineering staff as well.

MR. MONDROW: Okay. And you would include all of your third-party contractor costs in the calculation of the rate 400 agreement with the customer, presumably.

MR. McGILL: In terms of determining the rate 400 rate, yes, we would. We would be seeking to recover all of the capital costs associated with the installation of a facility.

MR. MONDROW: And have you considered at all the concept that we see in respect of connection of electricity, either load or generation systems -- the concept and the distribution system code of contestability, which defines what work the customer can get competitive bids on and what work they're required to contract for with you?

MR. McGILL: We haven't considered anything along that line.

MR. MONDROW: Okay. Just on the city of Toronto, I

think you've said this, but I just want to make sure.
So the city of Toronto plans to use the RNG in their own operations is your understanding?
MR. McGILL: We don't particularly know. I know in the early stages, we were led to believe that that was their desire. And then as we move through the process of negotiating with them, I think they started to explore other alternatives. But I don't have any direct knowledge of what they might be considering at this point in time.
MR. MONDROW: But in any event, they plan to deliver the RNG to your system and you will convey it on their behalf to wherever they want to it conveyed to?
MR. McGILL: Yes, that's my understanding of what they will seek.
MR. MONDROW: So they become a direct purchase customer of yours?
MR. McGILL: They already are.
MR. MONDROW: They already are?
MR. McGILL: Yes.
MR. MONDROW: Fair enough. So the RNG would fall under the direct purchase arrangement?
MR. McGILL: Yes. If they were going to consume the RNG at their own facilities, then that RNG would comprise part of their T-service and deliveries with respect to meeting their gas requirements under the transportation agreements.
MR. MONDROW: And use of the RNG in Ontario is not a condition of your agreement with the city of Toronto?

MR. McGILL: No.

MR. MONDROW: Okay. I'm sorry, I just forget if you said this. Is it your understanding that the city of Toronto is going to proceed whether or not Ontario government funding is available?

MR. McGILL: That's my understanding. As far as I know they are committed to going ahead with the project.

MR. MONDROW: So where are they going to get the funding; do you know?

MR. McGILL: They would have to determine how to do that themselves.

MR. MONDROW: Do you know, Mary? No. It's okay.

All right. Ms. Giridhar, I made you come back after lunch, so I'd better ask you some questions. I hope you're --

MS. GHRIDAR: Oh, don't feel bad. Sorry.

MR. MONDROW: I feel obligated. So you are bringing forward the RNG -- I think these are questions for you -- the RNG services proposed under section 36 of the OEB Act. You are asking for a rate order, essentially, is the relief requested in this proceeding, right?

MR. McGILL: Yes, that's what we're looking for.

MR. MONDROW: Okay, and so just sticking with injection for a minute, is that sale, distribution, or storage, in your view?

MR. McGILL: That would be distribution of gas --

MR. MONDROW: Would be distribution? Okay. And what about cleanup? Is that distribution?

MR. McGILL: Distribution of gas.
MR. MONDROW: Cleanup is a distribution function?
MR. McGILL: Yes.
MR. MONDROW: And that's by virtue of the fact that you now under cap-and-trade have a distribution company obligation to abate carbon? Is that what makes it distribution?
MR. McGILL: Well, that's part of it. I think the other aspect of it is that by my reading and understanding of the Ontario Energy Board Act, that raw untreated biogas fits within the definition of gas in the Act and that upgrading that gas to a quality that -- such that it can be introduced into our gas distribution system would be a gas distribution activity.
MR. MONDROW: But you also think that others can do that if they want to do that?
MR. McGILL: Yes.
MR. MONDROW: And they wouldn't do it as a distribution activity, right?
MR. McGILL: I wouldn't expect so, no.
MR. MONDROW: Okay.
MR. McGILL: I don't think it is a condition of the Act as to whether or not others can do certain functions.
MR. MONDROW: Sorry, I don't understand.
MR. McGILL: Well, I don't think it's a condition of the Ontario Energy Board Act that others couldn't perform that function.
MR. MONDROW: They wouldn't need a rate order to do

that from this Board?

MR. McGILL: That's right.

MR. MONDROW: Okay.

MS. GIRIDHAR: Yeah, I think just thinking that through, you know, there are certain things that we do, for example, I guess, natural-gas compression for vehicles is a service that we offer. Other entities can do that too. We have a distribution rate for natural gas vehicle --

MR. McGILL: Refuelling.

MS. GIRIDHAR: Refuelling.

MR. CHAGANI: Another example is customer piping on a private property. Enbridge will do it up to a building, but if the customer wants us to drop off the gas at an earlier point we would do that, and then they would build the piping downstream of our meter station. Both activities can be done by utility and in this case by the customer, and that's on private --

MR. MONDROW: Okay. No, that's helpful. So what you're saying is that when your pipe crosses on to -- crosses a property line, the fence, as you put it earlier, on to a person's property, that is no longer a regulated activity?

MR. McGILL: It depends where the meter is located. So we -- the utility assets end at the outlet of the meter, so if the customer wants us to, say, build a sales station at the property line and then take the gas from the meter along -- in their -- across their property to their building, then that's done, and is quite typical, or the customer might find it beneficial for us to extend our pipe across their property and locate the sales station and the meter adjacent to the building.

MR. MONDROW: So let's just be clear about what my question was. If Walker Environmental or Storm Fisher want to update their own biogas, they don't need to come to the OEB for a section 36 rate order, right?

MR. McGILL: Correct.

MR. MONDROW: Okay.

MR. QUINN: Can I add to that, Ian? Just on the last -- the example that you gave about the pipe being downstream of the meter, so customer piping, there isn't a regulated rate for that service, is there?

MR. McGILL: No, there's not.

MR. QUINN: So you do it on a cost-plus basis or how does that -- how does Enbridge charge for that?

MR. CHAGANI: No, so Enbridge would use our regulated rate to get to the point where we transfer custody to the customer.

MR. QUINN: The downstream part.

MR. CHAGANI: The downstream part. Enbridge is not building that part, the customer is building that pipe, and they don't have a regulated rate for that downstream pipe that goes from our meter to their burner tip.

MR. QUINN: So maybe I misunderstood. So Enbridge will not -- if a customer says they want it at their property line, Enbridge will not build the downstream piping?

MR. McGILL: No, we won't build the downstream piping --

MR. QUINN: Okay.

MR. McGILL: -- past the meter.

MR. QUINN: Okay, I misunderstood. I thought you were using that as an example of a service that you provide also as -- with the market. You are just saying anything upstream -- if it's on that property with upstream it's -- you will do it, if it's downstream you won't.

MR. McGILL: That's right.

MR. QUINN: Okay, that separates that out.

MR. MONDROW: Why not?

MR. McGILL: I'm not sure. I think it might go --

MR. MONDROW: There's an idea for you.

MR. McGILL: -- it might go back to the days of unbundling. You know, I think we probably would have been more inclined to do that kind of thing 20 or more years ago, but we don't do it today.

MR. MONDROW: Okay, thanks. Good.

Malini, there is also reference in the undertaking responses -- sorry, not the undertaking responses, the interrogatory responses to the undertakings, being the LGIC undertakings -- and I think they're also filed with the application if I'm not mistaken.

What part of the undertakings exactly are you relying on in respect of this application? Could you help me? And maybe we should go to them if we could. They are at Exhibit B, tab 1, Schedule 1, Appendix 1.

And I think what your evidence says if I recall it correctly is that these new business activities are provided for under the undertaking, so I'd like to understand that, please.

MR. McGILL: So I think what we are referring to can be found on page 10 of Appendix 1 of Exhibit B1, tab 1, Schedule 1, and this pertains more so to the geothermal energy service proposal that we have. It's paragraph (d), and this is the ministerial directive that goes back to -- this is the 2009 directive.

MR. MONDROW: So this is the first of the three directives you've got in this package, right?

MR. McGILL: I think there is the undertakings that go back to 1998 or '99, and then two ministerial directives.

MR. MONDROW: Okay, and so, sorry, you were -- so again, I'm talking about RNG, so is there something in here that applies to your RNG request?

MR. McGILL: No, we don't -- we believe that our RNG proposals are compliant with the undertakings because they are dealing with the distribution of gas as defined in the OEB Act.

MR. STEVENS: But in any event, Ian, to the extent that one would need to go beyond that, I think the reference that Steve was pointing you to, which is (d) on page 10 of 13 from the 2009 undertaking, broadly speaks of assets to assist the government of Ontario in achieving energy conservation goals.

MR. MONDROW: So RNG is an energy conservation initiative?

MS. GIRIDHAR: Certainly utilizes gas that will otherwise be wasted.

MR. MONDROW: All right.

MR. STEVENS: I think writ large it fits within the government's energy conservation and just general energy goals that have been expressed, whether it's been through the LTIP, the CCAP, or cap-and-trade, and just the various endeavours that are aimed at lessening the intensity of energy consumption and the emissions associated.

MR. McGILL: It's also -- I think the RNG proposal is also consistent with the letter that was sent to the chair of the OEB by the Minister of Energy in December 2016, and you can find that in Appendix 4 of Exhibit B, tab 1, schedule 1.

MR. MONDROW: All right, but that letter doesn't change either the OEB Act or your undertakings, right, Steve?

MR. McGILL: No, it doesn't. But I think it gives a pretty clear signal as to what the policy of the government was at the time.

MR. MONDROW: Yes, well, we all know how policies change, but fair enough.

But I was actually asking about the authority that you think -- or the contemplation that you think arises from the undertakings in respect of RNG, because that's what your evidence said and I think you've answered that it's conservation essentially?

MR. McGILL: Yes.

MR. MONDROW: Oh, it is distribution or conservation or combination of the two; Marion is correct.

Do you want to get up there?

MS. FRASER: No.

MR. MONDROW: Because you have to swear an oath. It's not a walk in the park by any stretch of the imagination. I should stop muddying up the record.

So in respect of the nascency of this activity -- and again, I'm talking about the clean up activity -- sorry, the upgrading activity -- if competition were to develop, if others started to coming into the market, would you -- as a utility, would you withdraw from the market?

Again, I'm talking about the market for upgrading services in particular.

MS. GIRIDHAR: You know, I mean we want to offer the service as long as it's useful to the marketplace, again going back to calling it an enabling service.

I just want to point out that there's precedents at the Board where we have undertaken activities and at a point in time, the Board ruled that there was competition sufficient to forebear and, you know, if that was the case and a regulated service was no longer required, we would be prepared to consider that at that point.

MR. MONDROW: So what are those activities?

MS. GHRIDAR: Well, I think our retail energy services -- I think you are quite familiar with those, Ian, that we got out of that about 20 years ago.

MR. MONDROW: But you it never did that as a utility. That was never in regulation.

MR. McGILL: What, the rental program?

MR. MONDROW: Sorry, energy services. I thought you meant the commodity. But sorry, the rental program.

MR. McGILL: The rental program was within the utility right up until the end.

MR. MONDROW: Retail means -- yes, right, the context has changed. The rental program; what else?

MS. GHRIDAR: Storage.

MR. MONDROW: Storage; anything else?

MR. McGILL: Well, I think there was a whole host of retail services we offered up until 2000. There was the rental program. We had appliance stores, we had merchandise financing programs.

MS. GHRIDAR: Insurance.

MR. McGILL: Heating plan insurance, we put insulation in attics and did all kind of different things, weather sealing, upgraded windows, doors.

MR. MONDROW: Yeah, okay, fair enough. And those retail energy services dated back to the 1950s, as I recall, right? You were building load -- not you, but your predecessors were building load.

MS. GHRIDAR: We were transforming the market.

MR. MONDROW: Transforming the market. Yeah, good call.

If competition were to develop and -- well, sorry, let me back up. Malini, you said if that were to happen, the

Board could forebear, which means, I guess, that they don't set a regulated rate for that.

MS. GHRIDAR: Correct.

MR. MONDROW: But then would you have to take the upgrading service out of the utility function? That's what happened with the retail energy service.

MR. McGILL: If it -- if it.

MR. MONDROW: And the storage that's now unregulated.

MR. McGILL: If that unfolded the same way as the situation we had with the retail businesses in the late 1990s, then yes, they would end up ...

MR. MONDROW: They would have to be removed.

MR. McGILL: Yes, similar to what happened to agent billing and collection. It started out in 1998 as a utility service, and then the Board determined that it should be operated on a non utility basis in the case of Enbridge, and we've operated it is a such since -- was it 1999, I believe.

MR. MONDROW: Until that happens, do you think you have an obligation to provide the upgrading service?

MS. GHRIDAR: It's a market facilitation role, so we want to be there for the customers and we want to be there for project proponents that want to bring RNG for our customers.

So I don't know whether it is an obligation; it is certainly a desire to enable the market. If I may provide a little more context on this?

MR. MONDROW: Absolutely.

MS. GHRIDAR: But I happen to sit on something called a clean tech strategy table that was initiated by the federal government, and the government has a explicit desire to incent adoption of clean technology in Canada and they are very interested in understanding the regulatory sandbox that we've operated at in the past that enabled, for example, a natural gas service to go from, I don't know, I guess from 200,000 customers in 1957 all the way up to penetration in excess of 95 percent of the marketplace by the time we reached the 1990s.

So there is an understanding that utilities play a facilitation role and especially as it relates to clean energy, that utilities can play a very supportive role for clean tech.

So it's not just us. I think there is appreciation for the role that utilities can play this space.

I just wanted to mention that.

MR. MONDROW: Sorry, I appreciate that. That would be a good discussion.

MR. MURRAY: That's right, Mr. Mondrow, a time check?

MR. MONDROW: You said go, I'm going. I still have some -- a few minutes. But if you want to take a break, I can come back to it, that's fine.

MR. MURRAY: Should we break until ...

MR. MONDROW: Maybe the court reporter would like -- why don't we take a break? Let's see, I'll try.

I'm just looking for my notes, Malini, because earlier you mentioned something about the Board approving in the past or permitting in the past a plain vanilla utility offering, I think was the term you used, alongside a competitive offering, and I am curious what you were referring to.

MS. GHRIDAR: I was referring to the commodity offering, so the fact that since the late '80s we have been offering -- I call it a plain-vanilla utility offering, because it's basically -- you know, it is a cost-based offering on commodity that has essentially a default that customers can take, and the Board enabled all kinds of other retail commodity offerings, you know, longer-term, different shade of pricing, et cetera.

And so I think GDAR is a good example where the Board ruled on a mechanism that allowed the utility to be there as a back stop and as a default, but also to have competitive offerings, which is really why I'm so enamoured by all of the thinking this Board has done in the natural gas industry space over the last 30 years and come up with a very rational framework that I believe can be applied here.

MR. MONDROW: I think I'm going to go, so we can both find it at the same time, to interrogatory response to Staff 7, which is under Exhibit I, tab 2.

This is something that we talked about earlier. I'm looking at the first page of the interrogatory under item C sub 1, which asked Enbridge Gas to explain whether it will enter into discussions with municipalities that are outside of its current service territory. So I guess we're talking pre-merger, and your response was, which you can see on page -- bottom of page 2:

"Enbridge has not entered into discussions with municipalities that are outside of its current service territory."

Fair enough, but that wasn't the question. The question was: Will you? So will you? Is there any reason you wouldn't? And this is in respect of upgrading services, by the way.

MR. McGILL: I think there is nothing to prevent us from doing that, but we haven't done that as of this point in time, and I think as we presumably move forward with further integration with Union Gas, this will be something that we address through that process.

MR. MONDROW: Okay. So just one more quick area. We talked about two other jurisdictions, Quebec and B.C. Those are the two jurisdictions that you've offered up as examples, and we talked a little bit about Quebec earlier, so we already know that upgrading is not part of the regulated distribution function according to the Régie in Quebec.

My understanding is that the issue of whether Energir, which is the new Gaz Métro, should procure RNG and pay a premium, is an issue that is currently before the Régie. Do you -- can you confirm that?

MR. McGILL: Yes, as far as I know that's correct.

MR. MONDROW: And has been before the Régie for some time.

MR. McGILL: I don't know how long it's been in front of the Régie.

MR. MONDROW: Okay. There is a large RNG facility in Quebec called -- or at Saint-Hyacinthe? I'm probably not pronouncing it right -- you're aware of that facility -- that facility was built, as I understand it, with municipal funding, upgrading facility?

MR. McGILL: I don't know.

MR. MONDROW: You don't know? Okay. There are a bunch of other pro -- RNG upgrading projects in Quebec currently -- facilities currently operating?

MS. GIRIDHAR: We know of one more if...

MR. McGILL: Yeah, we're aware of one other facility that's operating in Quebec at the moment.

MR. MONDROW: And other than Saint-Hyacinthe, those -- that other facility is selling its RNG to California, right? Do you know that?

MR. McGILL: I can't confirm that. I...

MR. CHAGANI: We know that it's injecting into TransCanada. We don't know where the gas goes beyond that.

MR. MONDROW: It's not being used in Quebec?

MR. CHAGANI: We couldn't tell you.

MR. MONDROW: Well, it's going into TransCanada, so it is not being used in Quebec, right?

MS. GIRIDHAR: It could be. I think it is going into the TQM system -- we are not aware --

MR. MONDROW: -- downstream? Okay. Fair enough. But I think the answer is you're not sure.

MS. GHRIDAR: Correct.
MR. McGILL: Correct.
MR. MONDROW: Okay. I believe that's it. Thanks very much. Thanks to the court reporter.
MR. MURRAY: Why don't we take -- Mr. Rubenstein, how long do you think you'll be?
MR. RUBENSTEIN: An hour. I don't know. Ten minutes, maybe, ten, 15 minutes.
MR. MURRAY: Umm... Why don't we take -- is ten minutes okay? If we only have ten minutes to go, ten-minute break, and we'll come back in ten minutes, at 4:00?
--- Recess taken at 3:49 p.m.
--- On resuming at 4:02 p.m.
MR. MURRAY: I think we'll get back to things, if everybody can please be seated.
I'm advised that OSEA, Ms. Fraser, doesn't have any questions, so I'm going to ask Mr. Rubenstein to go ahead with his questions.
EXAMINATION BY MR. RUBENSTEIN:
MR. RUBENSTEIN: Thank you very much. Can we start by going to SEC number 3, issue 1.
We had asked to provide the benefit of risks for each of the following parties: existing natural gas customers, RNG producers and Enbridge shareholders.
And for Enbridge shareholders, the comment is:
"Enbridge does not believe that its shareholders should bear any incremental risk with these abatement activities, given that the Board has

determined that GHG abatement activities are incurred as part of the utilities' role in providing distribution services similar to other delivery costs."

If the cap-and-trade program is wound down, does this response still apply?

MR. McGILL: In terms of the cap-and-trade program and the company's obligations under it, this response, I think, is devalued significantly in the way it's drafted now.

But I think coming back to the point I made earlier, that we view both the upgrading service and the RNG injection services as distribution services that should be regulated by the Board under sections 36 of the OEB Act.

So I’d come back to that as our support for going ahead with this on a regulated basis.

MR. RUBENSTEIN: I understand that. But do you believe that the -- I take it from reading this that you speak to GHG abatement activities as a reason why the shareholder should not bear any costs. But if there is no abatement framework similar to the cap-and-trade program, to you believe that the shareholder should bear any risk?

MR. McGILL: Well, I think what we said in the response is not bear any risk incremental to that that the shareholder already bears respect with respect to our regular business as it is today.

MR. RUBENSTEIN: All right. Could I now ask you to turn to Staff.9? It's in issue 2, I believe.

You were asked in part L for both the upgrading and injection service to provide -- to specify the major cost components of the O&M expenses.

MR. McGILL: Yes.

MR. RUBENSTEIN: And then you provide them. What you mean by consumables?

MR. McGILL: Could you repeat that, Mark?

MR. RUBENSTEIN: What is meant by consumables.

MR. CHAGANI: So there would be a number of consumables, for instance oil for the different parts. But the main piece over here is in part of stripping out the hydrogen sulphate in the biogas, you need activated carbon. So activated carbon is the consumable specifically that was -- or the majority of this would be activated carbon, but there would be a number of other small pieces that would be changed from time to time.

MR. RUBENSTEIN: As I understand for both the upgrading and the injection service, how the contracts are structured and the costs are structured for the purposes of the DCF analysis which makes up the rate, you will have a forecast capital cost that will ultimately -- ultimately the customers will pay the actual -- sorry, the RNG producer will pay the actual capital costs?

MR. McGILL: The rate will be based on the actual capital cost.

MR. RUBENSTEIN: But the O&M is a forecast cost for the length of the contract for whatever term it is; is that not correct?

MR. McGILL: Yes.

MR. CHAGANI: So I think we should take a step back there. With respect to the O&M, operating these facilities requires more than what you're seeing on Staff 9, part L.

There is electricity, which is the largest component.

It’s about 35 or 40 percent of the operating cost. That's not labeled here.

There is natural gas that may be needed. There is water. Those are the three main utilities. All of those will be borne completely by the producer. So we would take -- we would take a gas service that would be on their site, we would take an electricity service. But those would be their costs, they would be paying the monthly invoices.

So then there are some costs that we would be -- that would be incurred as part of our operation, those are the ones labeled over here, and there are a very small component in the overall operating of the facility.

MR. RUBENSTEIN: Is this $448,000 in total, or for the year that you are forecasting?

MR. CHAGANI: That's an annual amount per year.

MR. RUBENSTEIN: Let's say half a million dollars, roughly, but it is not about the magnitude. I'm just trying to understand.

You are forecasting that over the length of the term of the contract, 10, 15, 20 years, whatever it may be, correct?

MR. CHAGANI: Yes.

MR. RUBENSTEIN: So my question is -- I think there was some discussion about your previous experiences with a projection facility. I think you have one -- you were talking about this old facility that you have, and will that -- will it look, or will it be similar to this one, the one that you will be putting in place?

MR. McGILL: So to be clear, this interrogatory is dealing with the upgrading facility, not the injection facility.

MR. RUBENSTEIN: The injection is on the next page.

MR. McGILL: So the existing injection facility or transfer -- custody transfer station we have would be much less complex than what we would be seeing with respect to an RNG injection facility. So I think the cost associated with that would be much less; it’s much more straightforward.

MR. RUBENSTEIN: Well, lets put aside the magnitude; it is the secondary question. But I just want to understand conceptually here.

My understanding is you have one old injection facility and you have zero upgrading facilities that you currently operate.

MR. McGILL: Yes.

MR. RUBENSTEIN: So what type of experience do you have to be able to forecast 20 years O&M cost for these facilities?

MR. McGILL: Well, with respect to injection facilities, we operate -- I don't know, probably more than 20 gate stations off the TransCanada system, and we have years and years of experience with that work.

So, you know, that's informed a lot of the costs that have been set out in this example in evidence here.

MR. RUBENSTEIN: And what about upgrading?

MR. McGILL: With respect to upgrading, we haven't had experience operating an upgrading facility yet. But the costs we have are based on discussions we’ve had with service providers that would be participating in operating these services, and based on the contracts we would put in place for those services.

MR. RUBENSTEIN: So am I correct that if the operating costs end up being more than you forecast over the life of the contract, those costs will be borne by the remainder of your distribution ratepayers?

MR. McGILL: Well, they would have an impact on the actual cost of operating the system and if the costs were higher, the return on the investment in these assets would be less; if the costs were lower, they would be higher. But that's similar to the risks we have with respect to operating the rest of the system.

MR. RUBENSTEIN: I guess that depends on what you would be building into rates at any future rate case, correct?

MR. McGILL: Yes.

MR. RUBENSTEIN: And so are you saying that you will always build into rates -- you will not -- so let me put it this way: You will not build into rates at any time from today til the end of time, I guess, that we're doing these contracts, the O&M costs for any incremental O&M costs that you have to forecast to service these customers?

MR. McGILL: Can you give us one moment, please.

[Witness panel confers]

MR. CHAGANI: So Mr. Rubenstein, maybe I could direct you to the same Staff IR 9, bullet O, and if we go through the table, what we see is a number of different scenarios.

So if we look at the last scenario, this is the base case with a 10 percent increase in O&M, and what it shows is what the annual revenue would be, the accumulated NPV, and then the PI.

And what we're seeing is that the methodology that we have outlaid within our application shows that the PI still is above 1, even if there is a 10 percent increase in O&M for every single of the 20 years.

MR. RUBENSTEIN: All right. And I'm not sure what the number would be to take that down to below 1. 12 percent, 13 percent; correct?

MR. CHAGANI: Yes.

MR. RUBENSTEIN: That doesn't answer the question.

MR. McGILL: It would have to be much higher than a 10 percent increase for the full 20 years.

MR. RUBENSTEIN: Well, if 10 percent takes it down from 1.1 to 1.015, then 12 percent is taking that below 1?

MR. McGILL: Sorry. Yeah, so if it is lineal, which I'm not sure that it is, but if it were, a 10 percent increase in O&M for the full 20 years results in the PI dropping from 1.1 to 1.08, so that's 20 percent, so you would have to increase O&M by 50 percent for the full 20 years in order to bring the PI down to 1, which is still break-even from a ratepayer standpoint.

MR. RUBENSTEIN: Okay.

MR. McGILL: So I think the risk of increased O&M costs having a measurable effect on the feasibility of these projects is very, very low.

MR. RUBENSTEIN: Back to my original question. If you find out hypothetically after year 2 we really got it wrong. The cost is 30 -- O&M is going to be 30 percent every year more than we -- would you seek that -- would you seek to include that in your general -- whenever the next rate application you have, whenever the next cost-of-service rate application you have, to seek to recover that incremental amount from the rest of your customers?

[Witness panel confers]

MR. McGILL: I'm just trying to think through how the process -- yeah, how the -- how the process would work. We're just trying to think through how the process would work from a rate-setting standpoint, and I'll get back to you in a moment.

[Witness panel confers]

MR. McGILL: So Mark, the way I would look at this is that, you know, right now we have a proposal in front of the Board that would delay rebasing of our rates until 2029, so that to the extent that we had increased O&M costs beyond what we were expecting, that would be for our account up until that time of rebasing, and then at the time of rebasing we would look at our total cost in terms of determining a revenue requirement, seek to recover all those costs in rates.

MR. RUBENSTEIN: There was discussion about -- so as I understand it from your previous talking, for the capital cost, the RNG producer will pay the actual capital costs.

MR. McGILL: Correct.

MR. RUBENSTEIN: What about future capital costs that it may need because there needs to be an upgrade to some sort of cap -- one of the facilities within the larger injection facility needs maintenance work that would be a capital maintenance work, would those be recovered from that customer?

MR. McGILL: I believe we had an interrogatory response that spoke to that, and just give us a moment. We'll look at that before we respond to the question.

[Witness panel confers]

MR. RUBENSTEIN: If you want to answer by way of interrogatory, pointing to an interrogatory, if it exists, that's fine with me.

[Witness panel confers]

MR. CHAGANI: So while we find the IR response, the model would actually allow for, like, for us to build in future capital costs, so, for instance, on some of the plants that we're looking at, in year 10 or year 9 there is some membrane replacement, and so the membrane replacement, we would forecast that cost into our DCF analysis, and therefore it would be built into the fees, so that would be the first way that we could recover any future capital costs that are required, and we could do it as a -- depending on the way that the customer wanted to structure it, we could structure it that they paid in year 10 or earlier on, but the way that our model would be forecasted, throughout the life, from year -- from day one. We would forecast -- fat certain times we would need to put capital into it to replace certain parts. Those costs would be built into the forecast.

MR. RUBENSTEIN: But that would only be for expected capital work you know you'll need to do, so -- as you said, so you can just go to an RNG producer and says, just so you know, in year 8 these things always fail, we need to replace them, or, you know, the life expectancy of this widget is ten years, so we'll have to replace it, so we're going to build in those costs, but that does not account for anything that's unexpected; correct?

[Witness panel confers]

MR. RUBENSTEIN: APPrO.5, I'm being told, 2.APPrO.5, part D may be what you're looking at apparently.

MR. McGILL: The interrogatory that I'm thinking of is APPrO.5, part D. APPrO.5, part D so that was in issue 2.

So the question was: Please explain how Enbridge would account for further capital investment that may be required from time to time to continue to provide service over the life of the contract.

And the response was:

"The company will establish suitable warranties and protections from manufacturers and installation contractors to cover future unanticipated capital costs for RNG processing and injection facilities. Any change required by the customer will result in adjustments to the customer's fees to cover the associated additional costs."

MR. RUBENSTEIN: So I read that as -- now, my interpretation. Enbridge will try to have warranties and protections from manufacturers and contractors. But ultimately, you will bear the costs for things that are not being requested by the RNG producer?

MR. McGILL: I think to the extent that Enbridge had to bear any unanticipated or unforecasted costs that were weren't covered by the fee, we look at that as the same risk as we have today with respect to facilities that we install that don't last as long as we think they would, or require capital upgrades to. So those costs would be eventually recovered in rates through the same process.

MR. RUBENSTEIN: But in that situation, you allocate those costs to that rate class, generally. Here you are...

MR. McGILL: Well, there is a cost allocation process, and those costs would probably be allocated across all of the rate classes, depending on the nature of the expenditure.

MR. RUBENSTEIN: But here the only rate class that will not be allocated those costs would be those that are actually benefiting from it.

MR. McGILL: Yes, well, the one point is that the ratepayers stand to benefit to the extent that the sufficiencies over time, or the revenue sufficiencies over time will exceed the revenue deficiencies. So that serves as an offset to those costs.

MR. RUBENSTEIN: Now with respect to the capital costs...

MR. MONDROW: Sorry, Mark, before you leave, can I jump in?

So two things, Steve, one is that if you are actually proposing to have manufacturers and installation contractors cover future underscore unanticipated capital costs, there will be a premium associated with that that they will charge you, right?

MR. McGILL: And that will be included in the initial capital cost of the facility and recovered through the customer in the rate we charge them.

MR. MONDROW: Right, okay. And in respect of the point you just made to Mark about if beyond those warranties and protections, there was additional capital required, you would seek to recover that from all ratepayers.

The answer is that except for those ratepayers under the service who are obligated to pay you only what their contract says, right? So I think you acknowledged implicitly that those customers benefiting from those upgrades would not actually bear any portion of the costs to the extent that they spilled over into your other rates.

MR. McGILL: Yes, I just -- I agree with your statement, other than I wouldn't characterize these things as upgrades. These would be unanticipated costs that are required to keep the facility up and running. So it wouldn't be upgrades.

MR. MONDROW: Point taken, thank you. Thanks, Mark.

MR. RUBENSTEIN: With respect to capital costs, the end that the customer -- the actuals that the customers or the RNG producer will be required to pay for, does that include all the regulatory costs that may -- you may be incurred bringing forward a leave to construct proceeding for approval?

MR. McGILL: I'm not sure how we treat those costs today, but with respect to our leave to construct proceedings, my assumption would be that we would treat the regulatory costs associated with those applications in the same manner as we do today for regular leave to construct applications.

So I can take an undertaking to confirm that, but -- because I don't know what we do today, if we actually charge projects with the cost of regulatory proceedings associated with the leave to construct applications that support them.

MR. RUBENSTEIN: All right. Well, I'd like you to do that. I'd also like you to -- I know that to give us a forecast of what -- using, let's say, your model projects, what your expectation of that cost would be.

MR. McGILL: Okay, that's -- we'll have to make some assumptions in order to do that, but we can make an attempt do that.

MR. RUBENSTEIN: Just to get a sense of the magnitude.

MR. MURRAY: That will be undertaking JT1.14.

UNDERTAKING NO. JT1.14: TO CONFIRM WHETHER REGULATORY COSTS ARE INCLUDED IN CAPITAL COSTS THAT MAY BE INCURRED IN BRINGING FORWARD A LEAVE TO CONSTRUCT PROCEEDING FOR APPROVAL; TO PROVIDE MODEL PROJECTS SHOWING EXPECTATIONS OF WHAT THOSE COSTS WOULD BE

MR. RUBENSTEIN: With respect to the -- not if there's a required pipeline to be built, but with respect to the upgrading and injection facilities, would Enbridge require other permitting or other environmental assessment processes outside of anything that the Board would require in a leave to construct?

MR. McGILL: Yes, there are some permits that are required. Some of them would be obtained by the biogas producer. Some of them I believe that we would have to obtain principally from the Ministry of Environment and Climate Change so -- Mr. Chagani might be able to elaborate on that.

MR. CHAGANI: The main permit to be the site ECA. So presumably, most of these sites would already have an ECA, so there would be an amendment allowing Enbridge to build the facilities on the site.

MR. RUBENSTEIN: Who would be responsible for that?

MR. CHAGANI: It would be a combination of Enbridge and the site owner.

MR. RUBENSTEIN: Who would be paying for it?

MR. CHAGANI: If Enbridge was paying for it, it would be built into our service fees. If it was the site owner, then they would just absorb it.

MR. RUBENSTEIN: Could I ask you to go to -- well, I won't ask you about the interrogatory. But we had a discussion earlier on, and I interjected at some point earlier on today about the financial assurances.

MR. CHAGANI: Yes.

MR. RUBENSTEIN: And if we can go to Staff.16 -- this is number 2, issue 2 -- sorry, I may have that number wrong here. Sorry, Staff.6, this is a copy of the bio -- in the attachment 1 is the biogas services agreement opinion. If I could ask you to turn to page 14 of 92 -- sorry, 15 of 92 where it talks about the financial assurances.

And 13.02 says:

> "Any request for financial assurances should be based on the creditworthiness of the customer and shall be consistent with the company's then current policies relating to customer account security applicable to like customers."

Is there a written policy relating to customer account security?

MR. McGILL: Not that I'm aware of, no. I'm familiar with the process of how we go through our assessments of creditworthiness, though.

MR. RUBENSTEIN: So when do you decide that you require assurances or not? What is the --

MR. McGILL: Well, it would be based on the credit assessment of the counter party we're dealing with. So we basically do typical kind of credit checks, either through Equifax or Dunn & Bradstreet. We find out what the credit ratings are for those customers. We will review their financial statements and take into account, you know, the history of that organization.

We have analyst in our office that does that work, and they will come back to us with a recommendation as to how much security we require, and that analysis is consistent with the requirements of our corporate treasury department.

MR. RUBENSTEIN: And I assume for large customers, those who would be of the size that would -- and the type of entity that would take on this service, you're not 100 percent successful in recovering all fees owed?

MR. McGILL: We're not 100 percent successful, but I think based on our bad debt expense we have a very good track record.

MR. RUBENSTEIN: And would Enbridge be amenable either being in the rate handbook itself with respect to this rate or a Board condition with respect to, if it approves your application for language that would require the sufficient financial assurances to be provided to cover all undepreciated costs of the asset and removal and site remediation?

MR. McGILL: Just give us a moment, please.

[Witness panel confers]

MR. McGILL: I think as a practical matter it would be difficult for us to accept that kind of provision, in that we expect that the majority of the counterparties that we're dealing with in terms of these arrangements are going to be municipalities, and that, you know, their credit ratings typically well exceed our requirements, and that to go to them and ask for things like irrevocable letter of credits and -- letters of credit and whatnot, I think, would undermine our credibility with them, in fact, so to have some kind of blanket stipulation like that I think would be very problematic -- problematic --

MR. RUBENSTEIN: What about non-public sector entities?

MR. McGILL: Well, I think that's what we do today. We assess their creditworthiness. We have standards that apply, and then we seek security that's appropriate for that -- those individual entities based on those assessments, so like I said, I'm quite familiar with the process. I looked after credit collections for the company for a number of years, so I've been involved in lots of instances where we've pursued security from customers, where we don't have significant investments in facilities, we just have significant receivable risk with them. So I know exactly how the process works and I know exactly the steps we go through in order to obtain that kind of security, so that's what we would apply in the case of non-government entities in terms of providing this service or any other service that we provide.

MR. RUBENSTEIN: So back to my question: Would you agree to language in the rate handbook, your conditions of approval, for inclusion that would require sufficient financial assurances from producers to cover all undepreciated cost of the assets' removal site remediation if it was specific to private entities? If you'd like to think about it you can take an undertaking. I don't want to put you on the spot for something like that.

MR. McGILL: I am just reluctant to agree to something like that without taking it back for consideration.

MR. RUBENSTEIN: Fully understand.

MR. MURRAY: We'll mark it as an undertaking. JT1.15.

UNDERTAKING NO. JT1.15: TO ANSWER THE FOLLOWING QUESTION: WOULD YOU AGREE TO LANGUAGE IN THE RATE HANDBOOK, YOUR CONDITIONS OF APPROVAL, FOR INCLUSION THAT WOULD REQUIRE SUFFICIENT FINANCIAL ASSURANCES FROM PRODUCERS TO COVER ALL UNDEPRECIATED COST OF THE ASSETS' REMOVAL SITE REMEDIATION IF IT WAS SPECIFIC TO PRIVATE ENTITIES?

MR. RUBENSTEIN: Those are my questions. Thank you very much.

MR. MURRAY: Thank you. That concludes the technical conference on this matter.

--- Whereupon the hearing concluded at 4:39 p.m.