ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

Compendium for Examination
of Dr. Lawrence Kaufmann
by Enbridge Gas Distribution Inc.

February 20, 2014

ONTARIO ENERGY BOARD

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ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0459

VOLUME: Technical Conference

DATE: January 16, 2014

EB-2012-0459

THE ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

Hearing held at 2300 Yonge Street,
25th Floor, Toronto, Ontario,
on Thursday, January 16th, 2014,
commencing at 9:37 a.m.

TECHNICAL CONFERENCE

& Exporters.

MR. WIGHTMAN: James Wightman on behalf of VECC.

MR. AIKEN: Randy Aiken on behalf of Energy Probe. I would also like to register an appearance for David MacIntosh. He'll be joining us later.

MR. WOLNIK: John Wolnik for APPrO.

MR. MACMAHON: Pat McMahon with Union Gas.

MS. SEBALJ: Is that everybody?

MR. ROSS: Murray Ross with TransCanada.

MS. SEBALJ: All right. Was there anything of a preliminary nature from anyone? Enbridge? No?

Okay. I think the agenda has Dr. Kaufmann taking the witness box first.

DR. LAWRENCE KAUFMANN, PACIFIC ECONOMICS GROUP

I don't have anything of an opening nature. I don't know, Dr. Kaufmann, if you have anything or if we should just go straight to questioning.

My understanding is that Enbridge has the bulk of the questions for Dr. Kaufmann.

MR. CASS: We do indeed have some questions, Kristi. We were expecting that others would precede Enbridge in their questions for this particular witness.

MS. SEBALJ: Precede?

MR. CASS: Precede, yes.

MS. SEBALJ: And I should have mentioned Enbridge did file questions ahead of time. I'm not sure that that was the bulk of the questions, but I guess when we get to you we'll talk about those. I'm assuming you have others, but none of them apply to gas distribution studies.

There were no gas distribution TFP studies in Alberta other than the study that was submitted by Mark Lowry. The other studies that are mentioned here, the estimates from Brattle and others relied on either StatsCan studies or modifications of electricity distribution studies. And they also reference my TFP study for the electricity distributors in Ontario.

I should say that all of those, there's an issue here both about the studies themselves and whether they are viewed as credible. As I say, there were no credible studies. And none of these studies in Alberta were in fact accepted by the AUC, so they were all rejected as well. So that doesn't really support the view that those were considered credible.

That's not the case for the other TFP study, that was -- they mention, which is the electricity distribution TFP study that I did for Board Staff in the RRF and in support of what was called price cap IR. That was accepted by the Board, but that's my study and in my opinion that study is not relevant to this proceeding. We should not use an electricity distribution study to set or to even consider appropriate estimates for gas distribution TFP. Those are two different industries.

I've never supported using electric TFP studies for gas distribution. Gas distribution has different output growth, different cost drivers, different patterns of capital replacement, all kinds of things that can impact

TFP. In my opinion, there's no relevance or -- no relevance of or implications from that TFP study that I did for electric for an appropriate TFP trend for gas distribution.

And just very briefly, London Economics said a couple things about -- which may have been -- could potentially be misconstrued, about the whole issue of building blocks and the repeated nature of regulation and the implications of that for the building block model. And -- oh, and one of the things they said in discussing that was they were talking about my discussion of the UK experience, the UK building block experience. I believe they said several times that I posited a theoretical model for building blocks, and that -- that type of regulation, and that's not an accurate characterization of how I described that. What I was doing was looking specifically at the observed experience. I wasn't making any theoretical -- I wasn't developing any theoretical models. I was looking directly at the experience, which did in fact evolve over time, based on repeated interactions between the regulator and the regulated companies, and the gaming and inflated capital expenditure forecast in particular that the regulator noted after administering different applications of the building block model over a period, a number of years, 10, 15 years.

So I was just describing that experience; I was not making theoretical claims. And I also talked about the information quality incentive as something that they did eventually adopt in the UK.

I'm not making any recommendations that that type of incentive be implemented here, but I do think it's important. An element of the IQI is benchmarking. That is how the IQI starts. That's the benchmarks that capital expenditure forecasts are compared to. I do think it's important that there be some type of benchmarking, external objective evidence, benchmarking evidence. I believe that's an important -- that should be an important component of this proceeding. And that's really the claim I was trying to make in terms of the UK experience, the importance of benchmarking and the fact that the regulator there, as an attempt to offset the inherent incentives to the game projections that they discovered, that they observed over multiple iterations of the building block model, that they have gone to a very benchmarking-intensive regulatory approach.

So that's the point I was trying to make. I just don't want anyone to come away with a conclusion that I'm recommending an information quality incentive here. That's not what I'm recommending.

MS. DULLET: Thank you for your reply. I don't have anything further.

QUESTIONS BY MR. BRETT:

MR. BRETT: I have one follow-up on that. Tom Brett from BOMA. The decision of the Maine commission you referred to and the evidence of your former partner Dr. Lowry, are those part of the record now here? Or could you give us now or by way of undertaking just a reference where we can get those two documents?

DR. KAUFMANN: Yes, I can do that.

MR. BRETT: Do you need a number for that?

MS. SEBALJ: We do. That will be TCU1.1.

UNDERTAKING NO. TCU1.1: DR. KAUFMANN TO PROVIDE DECISION OF MAINE COMMISSION AND EVIDENCE OF DR. LOWRY.

MS.SEBALJ: Does anybody else have any questions for Dr. Kaufmann other than Enbridge? I see no one reaching for their mics, so I'll turn it over to you, Mr. Cass.

QUESTIONS BY MR. CASS:

MR. CASS: Thank you, Kristi. Dr. Kaufmann, as you know, I'm Fred Cass and I'm here for Enbridge Gas Distribution. I just wanted to start first with the written questions that were sent by Enbridge on January the 13th.

Can you give me a sense of how -- or maybe Kristi can help me -- how we will proceed with the responses to those questions? Do you have responses today, or will we be awaiting those responses?

DR. KAUFMANN: I'm prepared today to address the frost depth question, which I believe was number 6, so I can address that one today.

The others, let me see. I don't have that in front of me. Could we pull that up on the screen? Oh, I recall one was -- yeah, one is fine. I can find out -- let me just say I was not involved in this proceeding, did not bill a single hour to the CCA -- or is it the CCC -- in Alberta.

So for these questions, I do have to go back and ask other people in the office that were involved in this, to ask them these sort of details, but I can do that for number 1.

Number 2, we can --

MS. SEBALJ: Sorry. Why don't we just mark those as we go along, because I'm assuming that you are comfortable giving an undertaking to do that.

DR. KAUFMANN: I am.

MS. SEBALJ: So that -- so this is with respect to Enbridge's I.A1.STAFF.EGDI.12a. I just want to make sure I have the reference right.

MR. CASS: Sorry to interrupt. Would it make sense to mark the document as an exhibit, as a reference point for what we're talking about as we go forward here?

MS. SEBALJ: Because it did come in as correspondence, didn't it? Sure. So we'll mark this document -- sorry, I don't have it in front of me either anymore.

It's a letter from Enbridge providing questions in advance to Dr. Kaufmann and it's dated January 13th, 2014. And we'll mark it TC1.1.

EXHIBIT NO. TC1.1: LETTER FROM ENBRIDGE TO DR. KAUFMANN DATED JANUARY 13, 2014.

MR. CASS: Thank you. I don't know whether this will expedite things, but I do gather, then, Dr. Kaufmann and Kristi, that questions 1 to 5 will be undertakings and then we'll have some discussion here of 6?

DR. KAUFMANN: I have some comments on some of these others.

MS. SEBALJ: Why don't we go through them one by one? I think you're right; some of them will be undertakings, but some of them we need to speak to. So let's just go to number 2 now.

DR. KAUFMANN: Okay. Number 2 is fine. I can provide those work papers. Yeah, there was a follow-up, April 2012 report, that was primarily -- but that's fine. I can do that.

MS. SEBALJ: Sorry, so that's -- I'm going to keep interrupting you.

DR. KAUFMANN: Sure.

MS. SEBALJ: Very annoyed by me. That's TCU1.2.

UNDERTAKING NO. TCU1.2: DR. KAUFMANN TO PROVIDE A RESPONSE TO EGDI TCQ 2

DR. KAUFMANN: Okay. Now, for number 3, I'm fine with 3A and 3B. Those are basically calculations that can be -- that I can do based on the report that was actually submitted in Alberta, but C, D, E, and F, in my opinion, are overly burdensome to -- it's not -- and maybe I can just step back a little bit and talk a little bit about the Alberta work, because I did mention that in my report.

And what I did there -- let me just explain what I did and why I did it. What I did is I referenced an existing report from Alberta, and I said, Here is a report that has been submitted. It's been vetted. It wasn't ultimately approved by the regulator because of concerns with the confidentiality of the data, but it's still, in my opinion, a credible source of productivity and input price research, and the reason I did that is because I had gone through an extensive assessment of the company's proposal. I thought there were some, in my opinion, significant flaws with that proposal. I didn't know whether those flaws could be remedied in the time available, but I was not asked by the -- by Staff to prepare an alternate or counter-proposal, so I haven't done that. I have not put forward an alternate or counter-proposal here. All I did was say, Here's a source of information. If for whatever reason parties can't find -- can't agree on a customized IR framework without significant changes that Enbridge wouldn't agree to, if they can't do that, and they are looking perhaps during settlement or during another part of this proceeding for a source of information that could potentially be used to develop an alternate proposal, here's the source of information.

So I'm just pointing people in the direction of something that I think could be valuable, but I'm not recommending that as a study. I didn't undertake an alternate proposal on my own.

And given that, given that I'm not submitting this as evidence and making this my proposal, to add two years to a data set and -- that's not just kind of, you know, put the numbers in, pull the -- you know, turn the crank and get a new number. That's a significant undertaking. And I don't believe it's reasonable to ask us to do that in four days.

So C through F I think are unduly burdensome, but I can point you in the direction of a new PEG study which is in British Columbia, done for a consumer group, and I knew this study was in the works while I was writing my report, but it wasn't publicly available yet, so that's why I relied on the Alberta study, but now that study is out there, and it does go through 2011, so if Enbridge is interested in what PEG's estimate of a TFP trend through 2011 is, I would point you in the direction of that study in B.C., and I can make that available. That's a publicly available document. So I'm willing to do that, but other than that, I'm not going to ask people in the office to do new work when we've already kind of done that for another client.

For number 4, again --

MR. CASS: Sorry, can I just stop you there? My --

DR. KAUFMANN: Sure.

MR. CASS: -- apologies, Dr. Kaufmann. So we can -- you will answer 3A and B, and --

DR. KAUFMANN: I will answer 3B.

MR. CASS: And will you produce the B.C. study? Can we wrap that all up in one undertaking?

DR. KAUFMANN: I will produce that study.

MR. CASS: Thank you.

DR. KAUFMANN: Yes.

MS. SEBALJ: So it will be both the answers to A and B, 3A and B, and the production of the publicly available study, are TCU1.3.

UNDERTAKING NO. TCU1.3: DR. KAUFMANN TO PROVIDE THE ANSWERS TO EGDI TCQS 3A AND 3B, AND TO PROVIDE THE PUBLICLY AVAILABLE B.C. STUDY

DR. KAUFMANN: Yes, that's right.

For number 4, again, I -- because I did not formally proffer this study as my own or make it the basis for a proposal here, I don't think -- in my opinion it's not appropriate for me to go back and adjust that data and run alternate runs of a study that's part of a proceeding that's over and settled.

So, you know, I think, in my opinion -- and I'm not a lawyer. I'm only an economist. But in my opinion, this is out of scope for this proceeding. I'm not putting this forward as evidence, and I don't see why I need to run alternate analyses.

I can tell you, though, that we looked at -- we've examined the Concentric study, their TFP study, and the issue here is, what is the impact of customer service and information expenses on the TFP trend.

Customer service and information expenses were not included in the TFP trend in Alberta, but they were included in the Concentric study, and so we have looked at the impact on Concentric's TFP trend if they had eliminated customer service and CSI expenses, and if they would have, then the TFP trend would have declined by about 34 basis points.

So I can put that forward as an estimate, a rough estimate, of the impact of CSI expenses on TFP trends in the gas distribution industry, and this is part of the record here, it's part of Concentric, so it's easy enough for others to check our work and check the accuracy of that calculation.

So that would be my response to number 4.

MR. CASS: Well, I don't want to argue with you here, Dr. Kaufmann, about relevance. You've stated your view on that, or about what you call the scope of the proceeding. Clearly Enbridge is interested in having this information for the purposes of testing your views provided in this proceeding and considers it to be relevant.

Do you have a concern about actually doing the work? Other than your relevance concern, is there any problem with doing the work?

DR. KAUFMANN: The work can be done, but again, everyone is very busy at the office right now, and this is -- you know, to do this in four days, I'm not even sure we can get it done. There's much higher priority work that has to be done.

MR. CASS: I see. So just to be sure I understood, it could potentially be done in four days, but because of other work going on, that would be a problem for you. Is that what you are saying?

DR. KAUFMANN: That's correct.

MR. CASS: All right. Well, we'll leave it at that. We don't need to argue about it today. I assume, Kristi, that you are supporting the witness's view?

MS. SEBALJ: Absolutely. And I guess I would also refer parties to the original letter wherein we stated what Dr. Kaufmann's retainer was, and it wasn't to provide alternate proposals. It was to provide a critical analysis of the proposal before us from the applicant. And so I think this is treading into an area that we had not intended. Having said that, we can have the argument, and if the Board orders it, the Board orders it.

I just wanted also, though, for you to clarify. Does the B.C. study help in any respect with respect to CSI?

DR. KAUFMANN: I don't believe so. I believe the B.C. study also excludes CSI expenses, but I can confirm that.

MR. CASS: So, yeah, so we won't argue about it today. Now, Kristi, you did, just in -- what you said there, you referred to the -- you didn't use the work "instructions", but the scope of what Dr. Kaufmann was asked to do. And I wonder, could the instructions provided to Dr. Kaufmann in connection with this proceeding be produced?

MS. SEBALJ: Absolutely.

MR. CASS: Thank you.

MS. SEBALJ: We could mark that as TCU1.4.

UNDERTAKING NO. TCU1.4: TO PROVIDE THE INSTRUCTIONS PROVIDED TO DR. KAUFMANN IN CONNECTION WITH THIS PROCEEDING

MS. SEBALJ: And just to be clear, you're talking about the RFP document?

MR. CASS: I just need to see the --

MS. SEBALJ: Or the contract? I'm not sure that there is much difference between the two, in terms of -- I think we just transposed what we asked for in the RFP into the contract, but, yeah, we'll get you what you need for you to understand what his instructions were.

MR. CASS: Thank you.

Sorry, Dr. Kaufmann, so I guess we're on to question 5.

DR. KAUFMANN: Okay. Yeah. And on question 5, I do wonder, and I question the relevance of this question. It's referring to the econometric work that we did for Board Staff in the electric IR proceeding, the econometric work.

I haven't proposed any econometric work in this proceeding. I haven't done any work. And this is a model that's been thoroughly reviewed, thoroughly vetted and approved by the Board, so I don't understand why there's any relevance for trying to look at that, because it's not something that's -- the econometric for coefficients there don't have any implications for Enbridge, wouldn't be proposing those for Enbridge, so I just don't understand why this is a relevant issue. And, you know, in the interests of time constraints and budget implications for OEB, I just don't understand why it's worthwhile to pursue issues that in my opinion aren't really relevant for what I consider -- what I'm proposing and what I would consider relevant for Enbridge in this proposal.

MR. CASS: Okay. Well, again, I'm not going to debate it with you. You've given your position. So is there anything that you feel that you will or can provide in think is relevant there, the fact that companies keep incentive gains for -- the gains from efficiency initiatives for a common number of years regardless of the year that the initiative took place.

MR. CASS: Good. And that's good. So where I was going with my previous question I was going ask you next, are there any other design features that would cause you to support a particular ECM as the one you've described earlier, or are there any others?

DR. KAUFMANN: I think I would -- that's certainly the key one. I would have to look at -- you know, I'm not saying that that's the only way it can be done, but I would have to look at specific proposals to see if, you know, in my opinion, they achieve the same objective in a different way.

MR. CASS: Do you agree with the Board's objective for incentive regulation to encourage sustainable efficiencies?

DR. KAUFMANN: Yes, I do.

MR. CASS: And would you agree, then, that incentive regulation should be -- the incentives within incentive regulation should be aimed at sustainable efficiencies, as opposed to short-term cost-cutting?

DR. KAUFMANN: Yes.

MR. CASS: Thank you. Just a couple of questions for you arising from the RRFE, if you don't mind. Under the RRFE there is several models discussed, one of which is called custom IR. Would you agree that under the custom IR model for electricity distributors, as described in the

RRFE report, that such a model would not have to use an I-minus-X formula?

DR. KAUFMANN: Yes, it does not have to use an I-minus-X formula.

MR. CASS: Things are going much more quickly. And just one other question. Would you agree that the methodology for custom IR under the RRFE can take into account the circumstances of the particular utility? And I'm referring to methodology.

DR. KAUFMANN: Yes. Yes, and I think that's something the Board -- it's part of the Board's rationale for a customized IR.

MR. CASS: Okay. Thank you.

So I think I just have one last area, then. That went quite quickly. And it's page 47 of your report. I just wanted to pick up on one other -- page 47. Yes, top or bottom. Good point.

Bottom right corner of page 47 in the conclusion, second last sentence; you're describing some conclusions about Enbridge's plan, and in that context you say this plan can also contain Y factors that recover the costs of large capital projects. Are you with me?

DR. KAUFMANN: On page 47, at the upper right?

MR. CASS: Bottom right; my apologies. So it's your conclusion, in the second-last sentence.

DR. KAUFMANN: Okay, yes.

MR. CASS: There is a reference to the fact that a plan can contain Y factors that recover the costs of large capital projects.

DR. KAUFMANN: Yes.

MR. CASS: Now, would it be your view that Y factors can be structured in a manner to help an applicant get some certainty around the recovery of the costs of large capital projects?

DR. KAUFMANN: Yes, I think that's reasonable.

MR. CASS: And what about the situation where an applicant comes in for a term, say, of five years, but there really is uncertainty out in the latter years of that term about actually what the large capital projects might need to be.

Do you see -- I'm just asking for your comments. Do you see that Y factors can help with that at all?

DR. KAUFMANN: Yes, I think so. A Y factor application and mechanism can be implemented in a number of ways, and it can be something like a tracker so that it's designed to track expenditures, more or less every year, subject to a prudence review by the Board.

So if there is uncertainty and they can't be predicted in year one, you can still monitor the actual expenditures year-by-year.

You can make a prediction, an assessment projection on where they will be in year five, with the understanding there is some uncertainty around that.

But then they can be tracked year-by-year, and there could be protocol in place for the company to provide information on the costs, and some sort of information

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Ontario Energy Board

Ontario

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

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assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 09-30 October 30, 2009

Petition of Bay State Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 70 through 105, and for Approval of a Revenue Decoupling Mechanism.

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D.P.U. 09-30

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I. INTRODUCTION

A. Company's Filing

On April 16, 2009, Bay State Gas Company ("Bay State" or "Company") filed a petition with the Department of Public Utilities ("Department"), pursuant to G.L. c. 164, § 94, and 220 C.M.R. §§ 5.00 et seq., for a general increase in gas distribution rates.[1] The Company also requests approval of a decoupling mechanism and approval of a targeted infrastructure recovery factor ("TIRF") designed to provide the Company recovery of a portion of its reliability-related capital investments. The Department docketed the petition as D.P.U. 09-30 and suspended the effective date of the tariffs until November 1, 2009, for further investigation. Bay State's last general increase in distribution rates was approved on November 30, 2005, at which time the Department approved the implementation of a performance-based regulation ("PBR") plan for the Company. Bay State Gas Company, D.T.E. 05-27 (2005).

Bay State is incorporated in Massachusetts as a gas company, with its operations arising through the merger of local gas works, such as Springfield Gas Light Company, the Brockton Taunton Gas Company and Lawrence Gas Company (Exh. BSG/SHB-1, at 2). Currently, Bay State operates as a subsidiary of NiSource Inc. ("NiSource") (id.).[2] The Company provides

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1 Bay State filed for approval of tariffs M.D.P.U. No. 70 through M.D.P.U. No. 105.

2 NiSource, with headquarters in Merrillville, Indiana, is an energy holding company whose subsidiaries are engaged in the transmission, storage, and distribution of natural gas in a corridor stretching from the Gulf Coast through the Midwest to New England, and the generation, transmission, and distribution of electricity in Indiana. NiSource is a holding company under the Public Utility Holding Company Act of 2005.

retail natural gas distribution service to approximately 285,000 residential, commercial and industrial customers in the operating districts of Springfield, Brockton and Lawrence (id.). Although Bay State's three distribution service areas are not contiguous to each other, the Company operates on a centralized and integrated basis to the extent possible (id.).

B. Procedural History

On April 24, 2009, the Attorney General filed a notice of intervention pursuant to G.L. c. 12, § 11E. On May 12, 2009, the Department granted intervenor status to the Massachusetts Department of Energy Resources ("DOER") and the United Steelworkers of America ("USW"). On May 28, 2009, the Department granted intervenor status to Environment Northeast ("ENE"), Conservation Law Foundation ("CLF"), and the Low-Income Weatherization and Fuel Assistance Program Network ("Low-Income Intervenor"). Also on May 28, 2009, the Department granted limited participant status to Associated Industries of Massachusetts ("AIM") and The Energy Consortium ("TEC"); Boston Gas Company, Colonial Gas Company, Essex Gas Company, Massachusetts Electric Company, and Nantucket Electric Company, each doing business as National Grid ("National Grid"); Fitchburg Gas and Electric Light Company, doing business as Unitil ("FG&E"); The Berkshire Gas Company ("Berkshire Gas"); NSTAR Gas Company ("NSTAR Gas"); and Western Massachusetts Electric Company ("WMECo").

Pursuant to notice duly issued, the Department held three public hearings: (1) in Brockton on May 19, 2009; (2) in Lawrence on May 20, 2009; and (3) in Springfield on

May 21, 2009. The Department held 15 days of evidentiary hearings between July 7, 2009, and July 30, 2009.

On May 22, 2009, the Attorney General filed written comments. On June 4, 2009, the Company filed a request for leave to file reply comments, along with reply comments. The Department accepted the Company's reply comments for consideration. The Department also received written comments from a number of Bay State ratepayers.

On May 28, 2009, the Attorney General filed a Notice of Retention of Experts and Consultants, pursuant to G.L. c. 12, §11E(b), as amended by the Green Communities Act.[3] On June 10, 2009, the Department approved the Attorney General's retention of experts and consultants. Bay State Gas Company, D.P.U. 09-30, Order on Notice of Attorney General to Retain Experts and Consultants (2009).

The Attorney General, DOER, USW, ENE, and CLF submitted initial briefs on August 21, 2009. Bay State submitted its initial brief on September 4, 2009. The Attorney General, USW, ENE, CLF, and AIM and TEC submitted reply briefs on September 11, 2009. The Company submitted its reply brief on September 18, 2009. The evidentiary record consists of approximately 2,400 exhibits and responses to 187 record requests.[4]

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3 St. 2008, c. 169 is recently enacted energy legislation entitled An Act Relative to Green Communities. It is commonly referred to as The Green Communities Act.

4 The voluminous exhibits in this proceeding include responses to information requests and any attachments; confidential responses to information requests and any attachments; pre-filed direct testimony of witnesses; pre-filed rebuttal testimony of witnesses; attachments, schedules, workpapers and/or exhibits to the foregoing pre-filed testimony; revised or supplemental versions of the foregoing exhibits; and documents offered at the evidentiary hearings. The record also consists of three documents from

In support of its filing, Bay State sponsored the testimony of 13 witnesses: (1) Stephen H. Bryant, president of Bay State; (2) Daniel P. Yardley, principal, Yardley & Associates; (3) John E. Skirtich, consultant for Bay State; (4) James D. Simpson, vice president with Concentric Energy Advisors ("Concentric"); (5) Joel L. Hoelzer, vice-president of human resources, Bay State; (6) Lawrence R. Kaufmann, senior advisor to Pacific Economics Group LLC and to Navigant Consulting; (7) Shawn Patterson, senior vice-president of customer engagement, NiSource; (8) Willie Frank Davis, general manager, Bay State; (9) Paul R. Moul, managing consultant, P. Moul & Associates; (10) Robert B. Hevert, president, Concentric; (11) Joseph A. Ferro, manager of regulatory policy, Bay State; (12) Paul M. Normand, principal, Management Applications Consulting ("MAC"); and (13) Patricia Teague, contact center manager, Bay State.

The Attorney General sponsored the testimony of five witnesses: (1) David E. Dismukes, consulting economist and principal, Acadian Consulting Group; (2) Stephen G. Hill, principal, Hill Associates; (3) David P. Vondle, president, Vondle & Associates; (4) David J. Effron, consultant; and (5) Timothy Newhard, financial analyst, Office of Ratepayer Advocacy, Attorney General. The USW sponsored the testimony of one witness: Jodi Ajar, universal senior representative, Springfield call center, Bay State.

D.T.E. 05-27, incorporated by reference during the course of this proceeding (See Bay State Gas Company, D.P.U. 09-30, Hearing Officer Ruling on Request for Incorporation by Reference of Certain Material and Motion to Compel Response to Record Request (September 4, 2009)).

II. PERFORMANCE-BASED REGULATION PLAN

A. Introduction

In the following section we address two critical issues that will set the stage for the remaining decisions we make in this proceeding. The first is whether Bay State is authorized to seek an increase in cast-off rates during the term of its PBR plan. As set forth below, we answer this inquiry in the affirmative. Second, we must determine the effect, if any, of the Company's request for a rate increase on the continuation of its PBR plan. As set forth below, we conclude that the Company's PBR plan shall be terminated.

B. Description of the PBR Plan

In D.T.E. 05-27, the Department approved a ten-year PBR for Bay State. The rate plan commenced on December 1, 2005, and unless terminated, would remain in effect until October 31, 2016, with the last PBR-based rate adjustment taking effect on November 1, 2015. D.T.E. 05-27, at 398-401.

The rate plan provides for annual adjustments according to a price cap index (which includes an exogenous cost factor)[5] and an earnings sharing mechanism.[6] Id. at 360-361. The PBR plan also provides for a mid-term review in 2010 of the Company's PBR and its steel infrastructure replacement ("SIR") expenditures, if the Company's return on equity ("ROE") is below six percent. Id. at 400-401. These components of the PBR were designed by the Department to mitigate risks that shareholders and ratepayers may face as a result of a ten-year plan. Id. at 398-401.

Since the Department approved the Company's PBR plan, Bay State has made three annual compliance filings. In the first compliance filing, the Department approved a base distribution rate adjustment of $3,586,673, but rejected the Company's request to collect an

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5 Bay State's annual PBR adjustments are determined by applying a price cap index ("PCI") to the Company's then-current distribution rates under the following formula: $PCI_{new} = PCI_{current} * (1 + P - X) \pm Z$

where P is a factor that represents inflation,
X is a factor that represents a productivity offset factor, and
Z is a factor that includes costs associated with exogenous factors; i.e., those cost factors that are considered beyond the control of the Company, that affect the Company's unit cost but are not accounted for in the inflation component.

D.T.E. 05-27, at 360-361.

6 The earning sharing mechanism of Bay State's PBR provides for a deadband of 400 basis points around the Company's authorized ROE of ten percent. D.T.E. 05-27, at 401. If Bay State's actual ROE is 400 basis points or more below the authorized ROE, 75 percent of the loss would be borne by shareholders and 25 percent of the loss would be borne by ratepayers. Id. Conversely, if the Company's ROE exceeds its authorized ROE by 400 basis points or more, then 75 percent of the gain would accrue to shareholders and 25 percent to ratepayers. Id.

exogenous cost related to a decrease in the average use of gas per customer. Bay State Gas Company, D.T.E. 06-77, at 10, 14 (2006). In the second filing, the Company received a PBR adjustment of $5,882,030, which also included an earnings sharing adjustment of $2,590,693. Bay State Gas Company, D.P.U. 07-74, Letter Order at 2 (October 31, 2007).[7] In the third compliance filing, the Department approved a PBR adjustment of $2,648,986. Bay State Gas Company, D.P.U. 08-41, Letter Order at 3 (2008).

In the interim between the second and third compliance filings, Bay State petitioned the Department for rate relief to recover additional revenues as a result of a decline in the average use of gas per customer, and for recovery of non-revenue producing infrastructure investments through the SIR mechanism. Bay State Gas Company, D.P.U. 07-89 (2008). The Department rejected the request, concluding that no extraordinary economic circumstances existed to warrant the adjustment of the Company's rates outside the context of a full rate case. Id. at 21-25.

C. Company's Proposal

Bay State requests a change in the cast-off rates for the remaining term of its approved PBR plan. The Company cites two reasons for this filing. First, the Company states it made this filing in compliance with the Department's directive in Investigation Into Rate Structures that will Promote the Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008), for

7 Bay State subsequently discovered that its return on equity for 2006 was incorrectly calculated, and, as a result its PBR adjustment was reduced to $5,194,877 and the Company provided a voluntary refund to ratepayers. See D.P.U. 07-74, Letter Order at 1 (August 1, 2008); Exh. AG-32-17.

all distribution companies to be operating under decoupling plans by year-end 2012 (Exh. SHB-1, at 10; Exh. DPU-8-3). The Company notes that the Department emphasized its desire to implement decoupling mechanisms through a base rate proceeding so that those mechanisms would be initiated with a clear understanding of the utility's underlying distribution revenue requirement and allocation of the revenue requirement among customer classes through an allocated cost of service study (id., citing D.P.U. 07-50-A at 81). Bay State asserts that because the term of its PBR plan extends through November 2016, it became necessary for Bay State to prepare a petition for base-rate review under G.L. c. 164, § 94 in order to implement a revenue decoupling plan within the Department's timeframe (Exh. BSG/SHB-1, at 10-11).

Second, the Company states that its request for a change in base rates is necessary to address an operating revenue deficiency of $34,185,710 (Exhs. BSG/SHB-1, at 11; BSG/JES-1, Sch. BSG/JES-2 (Rev. 3)). According to Bay State, this deficiency exists as a result of a number of factors, including, but not limited to, long-term inflationary pressures on operations and maintenance ("O&M") expenses, unrecovered costs of replacement activities of non-cathodically protected bare-steel, adverse capital market conditions, and declining customer usage not anticipated when base rates were last set in 2005 (Exhs. BSG/SHB-1, at 5, 11, 17-20; DPU-8-1, at 3). In particular, the Company states that although the PBR plan is appropriately structured to provide the incentives for long-term cost reductions that will benefit customers, the plan was founded on cast-off rates set on the basis of sales volumes experienced in the test year ending 2004, which no longer are available to the Company (Exh. BSG/SHB-1, at 11). Further, Bay State explains that the PBR plan fails to compensate for the timely recovery of incremental capital investment made for safety and reliability purposes (id.). Bay State maintains that this shortcoming places the Company at a significant disadvantage in terms of maintaining an adequate return and attracting the capital necessary to fund infrastructure replacements or technology initiatives (id.).

The Company states that it attempted to address its declining financial condition without initiating a base rate proceeding, but its proposals were rejected by the Department in D.P.U. 07-89 (Exh. DPU-8-1, at 2). Bay State stresses that it cannot continue to operate on the basis of a revenue stream that is insufficient to recover the cost of providing service, including a fair and reasonable return (id.). Therefore, the Company contends that it was required to petition for a change in base rates during the term of the PBR plan (id.).[8]

Aside from an increase in cast-off rates, the Company is not proposing any modifications to the currently effective PBR plan approved in D.T.E. 05-27, should the Department approve the Company's proposed decoupling mechanism (Exh. DPU-8-4). Thus, the Company proposes to continue the existing PBR, including all current reconciling mechanisms, after the implementation of decoupling (id.; Exhs. BSG/SHB-1, at 9; AG-8-8; AG-8-9; Tr. 12, at 2023-2024).[9]

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8 The Company also cites our decision in D.P.U. 07-50-A and, specifically, the requirement that we examine decoupling mechanisms in the context of a full base rate proceeding (Exhs. BSG/SHB-1, at 10-11; BSG/JES-1, at 10; Tr. 7, at 971, 994).

9 The Company represents that, because of its request for a base rate increase, it will not seek a PBR adjustment for 2009 (RR-DPU-31).

D. Position of the Parties

1. Attorney General

The Attorney General argues that Bay State's request to raise rates outside of the PBR must be rejected, and the current PBR must be permitted to continue in order for customers to receive the significant cost savings and other benefits to ratepayers to which they are entitled (Attorney General Brief at 48). The Attorney General contends that resetting or establishing new cast-off rates during the course of the PBR plan defeats the concept of customer benefits flowing from the long-term nature of the plan (id.). The Attorney General asserts that the PBR plan encourages Bay State to operate efficiently by allowing the Company a degree of earnings flexibility in exchange for limitations on filing a rate case until the expiration of the plan (id. at 48-49). Further, the Attorney General contends that such symmetry affords the utility the flexibility to operate efficiently by encouraging up-front expenditures in the near-term that have the potential to reduce overall cost of service and substantial earnings improvement over the long-term (id. at 49). The Attorney General claims that the rate adjustments under the PBR plan compensate Bay State for changes in costs, inflation, and capital investments, while assuring ratepayers that increases over the life of the plan are capped and cannot exceed the level fixed within the PBR formula (id.).

The Attorney General argues that the Company simply uses the Department's decoupling Orders as the pretext to amend its PBR by seeking an increase in its distribution rates and arguing for a recovery mechanism for SIR replacement costs (id. at 49-50). The Attorney General asserts that the Department must reject the Company's proposal as unjust and unwarranted and allow the PBR the opportunity to run its term and fulfill its intended goals (id. at 50). The Attorney General cites several reasons why the PBR should continue unchanged.

First, the Attorney General acknowledges that Bay State is entitled to just, reasonable, and non-confiscatory rates (Attorney General Reply Brief at 11). The Attorney General asserts that a PBR plan provides a framework for achieving that end by offering the Company the same incentives that exist for competitive firms, within the context of permitted price increases, to reduce its costs, expand its productivities, and, thereby enhance shareholder returns (id.). In this regard, the Attorney General submits that a PBR plan is not designed to ensure any level of return for the Company (id.).

Next, the Attorney General asserts that, in evaluating Bay State's claims that its present earnings results are deficient, the Department has wide discretion to consider the mode of regulation to apply to ensure Bay State's rates are just and reasonable (Attorney General Reply Brief at 12). The Attorney General contends that because the Company's revenues, expenses and investment are constantly in flux, there is no single just and reasonable rate compelled by statute (id.). Thus, according to the Attorney General, rates in effect are presumed just and reasonable until such time as the Department finds, after investigation, existing rates are no longer just and reasonable (id., citing D.P.U. 87-21-A at 6). The Attorney General asserts that this investigation includes evaluating the Company's test year submissions, as well as future rate increases and savings likely to flow under the PBR plan (Attorney General Reply Brief at 12).

Third, the Attorney General argues that, as a prerequisite to terminating the Company's existing PBR plan and/or to modify its terms, the Company bears the burden of demonstrating that its current rates under the existing PBR are unjust and unreasonable (Attorney General Brief at 13). The Attorney General contends that without such a showing, the Company's petition must be dismissed (id. at 13-14, citing Riverside Steam & Electric Company, D.P.U. 88-123, at 26-27 (1988)). Further, according to the Attorney General, Department precedent establishes that companies operating under a long-term PBR may only "'petition the Department for changes in tariffed rates in reaction to extraordinary economic conditions'" (id. at 14, citing D.P.U. 07-89, at 17; Bay State Gas Company, D.T.E. 03-40, at 497 n.263 (2003)). Thus, the Attorney General contends that, at the very least, the Company bears the burden of demonstrating that (1) it is facing extraordinary economic conditions, (2) its existing rates are unjust and unreasonable, and/or (3) the existing PBR plan results in confiscation of its property (id. at 14). In this regard, the Attorney General contends that Bay State's claimed revenue deficiency is overstated and erroneous (Attorney General Reply Brief at 13).

Fourth, the Attorney General argues that the Company's earnings are in line with the parameters of its PBR plan (Attorney General Brief at 47). Specifically, the Attorney General notes that the Company's reported earned return under the PBR has increased since the rate plan began, and for 2008 was 6.23 percent, which was within the bandwidth set out by its PBR (id. at 50). The Attorney General contends that Bay State has the opportunity to obtain future annual rate increases under the PBR, with only simple filings and cursory review (id.). Further, the Attorney General claims that Bay State's guaranteed recovery of inflation-related

PBR adjustments, coupled with its opportunity to collect exogenous costs under certain conditions, reveals that the Company does not need to change its PBR, either by increasing rates by more than $34 million or through adoption of the TIRF proposal (id.). The Attorney General asserts that implementing the decoupling recommendations she proposes within the framework of Bay State's current PBR yields rates that continue to be just and reasonable (Attorney General Reply Brief at 13).

Finally, the Attorney General notes that the Company has not yet reached the half-way point in its PBR term (id.). Thus, the Attorney General argues that permitting the Company to reset cast-off rates now would be premature and unjustified (id.). Instead, the Attorney General contends that the Department should not abandon its requirement that Bay State operate without a rate case for ten years under its PBR in exchange for the financial benefits that it receives in the way of annual rate increases (id.).

2. USW

USW does not oppose the maintenance of the Company's PBR plan in conjunction with the implementation of decoupling (USW Brief at 32). USW, however, expresses concern that Bay State will reduce in-house staff needed to provide knowledgeable, safe and sufficient service quality (id. at 32-35). Thus, USW requests that the Department craft oversight mechanisms to ensure that the Company maintains adequate staffing to meet its safety, reliability, and service quality obligations (USW Brief at 35). In addition, USW requests that the Department open a service quality/staffing docket following this case to address whether

Bay State is in compliance with G.L. c. 164 § 1E(b) and whether additional service quality performance measures are warranted (id.).

3. Company

Bay State argues that, regardless of the ratemaking methodology used by the Department and irrespective of the PBR plan, the Company has the statutory right to petition the Department pursuant to G.L. c. 164, § 94 to establish just and reasonable rates where its existing rates are no longer providing an adequate return (Company Brief at I-III.17, citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 299-300 (1978); Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, at 10-12 (1978); Fitchburg Gas and Electric Light Company, 371 Mass. 881, 884 (1977); Company Reply Brief at 7-8; Exh. DPU-8-1, at 2). The Company contends that the option to seek rate relief through the mid-point review[10] of the PBR plan or through the "extraordinary economic circumstances"[11] provision of the PBR plan does not supplant the statutory right to seek a rate

10 The Company contends that the Department's review of the Company's request for base rate relief would arguably represent a "mid-period review" of the PBR plan (Exh. DPU-8-1, at 3, n.1, citing D.T.E. 05-27, at 401). In D.T.E. 05-27, however, the Department did not provide that the mid-point review would constitute a base rate proceeding or provide the Company with the right to seek an increase in cast-off rates. D.T.E. 05-27, at 401.

11 The Company distinguishes its claimed statutory right to seek a rate increase from its "option" under the PBR plan to request a change in cast-off rates due to "extraordinary circumstances" (Company Brief at I-III.21 through I-III.22). Bay State argues that while the Department's establishment of "extraordinary economic circumstances" as a basis for rate relief during the term of a PBR plan is a reasonable exercise of its discretion, the existence of this option cannot lawfully bar the Company from seeking base-rate relief under § 94 during the plan where the Company's rates are no longer

increase under § 94 (Company Reply Comments, at 4-5; Exh. DPU-8-1, at 2-3). Further, the Company claims that, once such a petition is filed, the Department is obligated to investigate the proposal and to determine the propriety of the proposed rates to determine if they are just and reasonable (Company Brief at I-III.17 through I-III.18, citing Attorney General v. Dep't. of Telecommunications and Energy, 438 Mass. 204 n.13, 256, 268 (2002); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984); Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Company Reply Comments at 5). Additionally, Bay State contends that the rates ultimately set by the Department must allow a fair rate of return to investors on the value of property used in providing those services (Company Brief at I-III.18 through I-III.19, citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 205 (2001); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265-266 (1984); Massachusetts Elec. Co. v. Department of Public Utilities, 376 Mass. 294, 299 (1978); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 371 Mass. 881, 884 (1977); Company's Reply Comments at 5). The Company asserts that the Department has consistently acknowledged and adhered to these ratemaking principles when approving utilities' rates (Company Brief at I-III.19 through I-III.20, citing Investigation Into Rate Structures that will Promote the Efficient Deployment of Demand Resources, D.P.U. 07-50-B at 37 (2008); D.T.E. 03-40, at 496; D.P.U. 94-158). Thus, Bay State argues that so long as it demonstrates that its proposed rate changes are

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just and reasonable because the revenues generated by those rates are insufficient to cover its costs and provide an adequate return (id.).

necessary to recover its reasonable and prudently incurred cost of providing service to customers, including a fair return on its investment, both Massachusetts law and Department precedent provide that the Company is entitled to new rates (Company Brief at I-III.20 through I-III.21; Company Reply Comments at 5).[12]

Further, the Company argues that the PBR plan approved by the Department was not designed to ensure just and reasonable rates or an adequate return on equity for the Company over the ten-year term of the plan (Company Brief at I-III.27; Exh. DPU-8-2). Rather, Bay State contends that the fundamental theory underlying PBR is that it establishes an alternative ratemaking framework, involving a set of financial incentives that is designed to better encourage utilities to improve efficiency over time than would otherwise occur under traditional cost of service/rate of return ratemaking (Company Brief at I-III.27, citing D.P.U. 94-158, at 40, 46). Bay State argues, however, that PBR does not change a utility's fundamental constitutional and statutory right to rates that, in the end, compensate it for the cost of providing service to customers, including a fair return (Company Brief at I-III.28, citing D.P.U. 94-158, at 46; D.P.U. 07-50-B, at 36-37).[13] Bay State argues that this is true

12 The Company rejects the Attorney General's notion that Bay State must demonstrate, as a prerequisite for a rate increase, that existing rates are unjust and unreasonable or confiscatory (Company Brief at I-III.23). Further, Bay State contends that the implementation of its PBR plan does not create a presumption, which the Company is required to rebut, that existing rates are reasonable (id.). Rather, the Company argues that its burden is to demonstrate the need for new rates to recover reasonably and prudently incurred costs and a fair rate of return (id. at I-III.24).

13 Bay State asserts that because customers are obligated to pay for their proportionate share of the full cost of providing service, including a fair and reasonable return for the Company, customers do not have a reasonable expectation that rates will remain

even where the Company's earned rate of return falls within the bandwidth set out by its PBR (id. at I-III.29 through I-III.30).

Bay State also argues that its request for a rate increase is consistent with the Department's decision in D.P.U. 07-50-A. Specifically, Bay State contends that the Department's decoupling decision provides for the filing of a decoupling proposal in the context of a full base rate proceeding (Company Reply Comments at 6-7). The Company contends that it has followed the approach outlined by the Department in D.P.U. 07-50-A, producing a traditional cost-of-service revenue requirement and an allocated cost of service study, as well as in terms of maintaining the existing PBR plan (id. at 8). By doing so, the Company argues that it has demonstrated that its proposed rates are necessary to allow for recovery of its reasonably and prudently incurred operating expenses, while also providing a fair and reasonable return (Company Brief at I-III.25 through I-III.26).

Regarding the continuation of the PBR plan, the Company asserts that no fundamental precept within the theory or practice of PBR requires the termination of a PBR plan because new cast-off rates may be needed, particularly when those cast-off rates are intended to comply with a new policy mandate of the public utility commission (i.e., the implementation of revenue decoupling) (Exh. DPU-8-7, at 1).[14] Further, Bay State argues that its request to

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unchanged over the ten-year period of the PBR plan, especially where those rates are not just and reasonable (Exh. DPU-8-2).

14 The Company contends that, even if the Department terminates the PBR plan, the establishment of new castoff rates would not affect or diminish the public policy benefits of continuation of the earnings sharing mechanism, exogenous cost recovery mechanism and the PBR rate adjustment formula (i.e., inflation less productivity factor)

continue the PBR plan is consistent and compatible with the Department's explicit directive in D.P.U. 07-50-A regarding the implementation of revenue decoupling in conjunction with an inflation factor (Exh. DPU-8-3, at 2, citing D.P.U. 07-50-A at 48-50; Tr. 7, at 994-995).

In addition, the Company contends that its PBR plan has served a valid purpose in terms of providing a modicum of relief on an annual basis from O&M cost increases because of the inflation factor incorporated in the PBR plan (Company Brief at I-III.12-13). The Company argues that if the PBR plan is permitted to continue, recovery of the annual PBR revenue target through the revenue decoupling mechanism will be a straightforward calculation that will not necessitate any changes to the existing compliance filings or calculations (Company Brief at I-III.16). As a result, the Company contends that there is no adjustment that the Department would need to make to accommodate the PBR plan operation in conjunction with the proposed revenue decoupling mechanism (id.).

Moreover, the Company notes that the PBR plan, when compared to traditional cost-of-service regulation, creates stronger incentives for the Company to control costs, to price efficiently, to allocate resources more efficiently, and to be more innovative (Exh. LRK-1, at 6-12). Further, the Company maintains that termination of the plan would lead to

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(Exh. DPU-8-7, at 1). More specifically, the Company contends that a continued application of the PBR rate adjustment formula over a multi-year period would allow the Company to avoid frequent base-rate increases and would create stronger incentives to implement longer-term cost reduction strategies (id.). According to Bay State, these two goals are linked in that utility management is more likely to undertake longer-term cost reduction strategies under multi-year PBR plans, since these plans increase the probability that the firm will recoup some or all of its up-front investment costs before the savings resulting from the initiative are flowed through to customers in base rates (id. at 1-2).

more frequent rate cases that consumes management's time, makes it more difficult to focus on running the Company, and creates the wrong set of incentives that has previously led the Department to reject the cost-of-service approach in the past (Exh. BSG/LRK-1, at 18; Tr. 7, at 999).

Finally, the Company asserts that it structured its filing in this proceeding on the assumption that the PBR plan would continue for its remaining term, and therefore, the Company could continue with the PBR plan following the implementation of revenue decoupling and other rate changes (Company Brief at I-III.13). Bay State submits, however, that if the Department determines that the PBR plan must be voluntarily terminated pursuant to D.P.U. 07-50-A to effect these changes, then the Company is willing to voluntarily terminate the plan (id. at I-III.12, 13; Tr. 12, at 2025).[15]

E. Analysis and Findings

1. The Company's Request for a Base Rate Increase

Companies operating under a PBR are not expected to seek changes to base rates outside of the annual PBR adjustments mechanism. See e.g., D.P.U. 94-158, at 22.[16] General base rate changes are usually reviewed in general rate cases pursuant to G.L. c. 164,

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15 Bay State contends that the public policy benefit of maintaining the earnings sharing mechanism, exogenous cost recovery mechanism and the PBR rate adjustment formula (i.e., inflation less productivity factor) is not affected or diminished by the establishment of new cast-off rates, so the factors that led the Department to approve these regulatory mechanisms as part of PBR would equally apply even if the PBR plan was terminated (Exh. AG-8-7).

16 PBR mechanisms may include an exogenous cost provision and an earning sharing mechanism.

§ 94. See e.g., Massachusetts-American Water Company, D.P.U. 95-118, at 175 (1996); Housatonic Water Works Company, D.P.U. 95-81, at 3 (1996); Commonwealth Gas Company, D.P.U. 92-151, at 4 (1992); Boston Edison Company, D.P.U. 92-23/92-24, at 4 (1992); Tax Reform Act, D.P.U. 87-21-A at 6-7. When approving long-term PBR plans, however, the Department has taken note of opportunities available to companies to change rates under such plans. These opportunities have included a formal mid-period review (see The Berkshire Gas Company, D.T.E. 01-56 at 10-11 (2002); D.T.E. 03-40 at 497), and acknowledgment that companies retain the option to petition the Department for changes in tariffed rates in reaction to extraordinary economic conditions. D.T.E. 05-27, at 400; D.T.E. 03-40, at 497 n.263. Neither option is before us in this proceeding.

This is the first instance in which a regulated utility operating under a PBR plan in Massachusetts has sought to establish new rates during the term of the rate plan by filing for a general rate increase based on an updated cost of service and revenue requirement.[17] Bay State seeks to establish new rates by presenting a new test year of costs and revenues. Bay State asserts that the impetus for the filing of this rate case was twofold: (1) the Department's decision in D.P.U. 07-50-A; and (2) a need to address an operating revenue deficiency of $34,185,710 (Exh. BSG/JES-2, Sch. BSG/JES-1 (Rev. 3)).

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17 The Company's limited request for rate relief in D.P.U. 07-89 sought a modification of test year billing determinants, as well as a steel infrastructure replacement recovery mechanism, which the Company claimed was necessary to address declining use per customer. D.P.U. 07-89, at 1.

G.L. c. 164, § 94 expressly provides that "[r]ates, prices and charges in such a schedule may, from time to time, be changed by any such company by filing a schedule setting forth the changed rates, prices and charges . . . ." Further, in rejecting arguments opposing a ten-year PBR plan for Boston Gas Company, we concluded that "a ten-year PBR plan would not alter substantive rights retained by Boston Gas by statute to file a rate case if rates are not just and reasonable. Department actions cannot abrogate statutory rights in rate setting." D.T.E. 03-40, at 496, citing Eastern-Essex Acquisition, D.T.E. 98-27, at 14-21 (1998). Thus, the Department's approval of a PBR mechanism cannot trump the statutory rights granted as a part of G.L. c. 164, § 94.

Moreover, the Company's filing and request for a base rate increase is consistent with the Department's Order in D.P.U. 07-50-A. In that proceeding, we expressed a desire to avoid the implementation of decoupling in a piecemeal fashion, i.e., by permitting distribution companies to layer decoupling proposals on top of existing rates. D.P.U. 07-50-A at 81-82. As such, we concluded that, when a company files a proposal for a revenue decoupling mechanism it should do so in conjunction with the filing of a base rate proceeding. Id. at 82. The objective of this requirement was to ensure that rates would be set for decoupling purposes based on an understanding of the company's underlying distribution revenue requirement and an allocation of this revenue requirement among customer classes through an allocated cost of service study. Id. at 81.

Based on our review of relevant authority, we find that Bay State has the statutory right to seek rate relief, even during the term of its PBR plan, through the filing of rates based on updated costs and revenues, i.e., a new test year. Next, we address the termination of Bay State's PBR plan in light of the Company's request for a base rate increase.

2. The Termination of the Company's PBR Plan

In D.P.U. 07-50-A, we concluded that we would not force the early termination of a currently effective rate plan. D.P.U. 07-50-A at 49. In doing so, we did not foreclose the possibility of implementing decoupling in conjunction with a PBR plan. Id. at 49-50. Instead, we noted that we would consider company-specific rate making proposals when implementing decoupling. Id. at 50. In the instant case, Bay State seeks to establish new cast-off rates, but continue its PBR plan in all other respects.[18]

The Company's rate plan is currently built on cast-off rates established in 2004 and intended to be in place, subject to annual adjustments, for a period of ten years. D.T.E 05-27, at 399-400. Thus, ratepayers have a reasonable expectation that base rate increases over the term of the PBR will be less than the rate of inflation, subject to any exogenous cost or earning sharing adjustments. The establishment of new rates based on a new test year of costs and revenues completely changes the dynamic of the Company's rate plan. In seeking to establish

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18 In D.P.U. 07-50-A, we also noted that we would permit a company to voluntarily terminate a rate plan in order to implement decoupling. D.P.U. 07-50-A at 83. The Company states that, if the Department determines that voluntary termination of the PBR plan is a prerequisite to implementing decoupling, then the Company was willing to voluntarily terminate the plan (Tr. 12, at 2025, 2112-2113). We do not consider voluntarily termination a prerequisite to implementing decoupling. Further, the Company's offer can hardly be deemed "voluntary" given that its filing is premised on the continuation of the PBR plan (See Company Brief at I-III.13).

new rates, the Company seeks to change a fundamental component of the PBR plan, and a very significant aspect of the rate plan from a customer's perspective; that is, the expected level of base rates that customers will pay over the term of the rate plan. Further, as the Company expressly recognizes, the fundamental theory underlying PBR is that it establishes a set of financial incentives that are designed to better encourage utilities to improve efficiency over time than would otherwise occur under traditional cost of service/rate of return ratemaking (Company Brief at I-III.27, citing D.P.U. 94-158, at 40, 46). The establishment of a new level of rates based on an updated test year of costs and revenues runs contrary to these principles and changes the economic incentives to pursue medium and long-term planning and business decision making. See D.T.E. 05-27, at 399. Further, the components of the Company's PBR plan, including its price-cap formula, are integrally related and, as such, are dependent upon each other to balance the benefits between shareholders and ratepayers. An interim change in rates, such as those based on an updated test year of costs and revenues, alters this balance. Based on these considerations, we conclude that the establishment of new base rates in this fashion subjects Bay State's existing rate plan to termination.[19] The Company's ten-year rate plan, as approved by the Department in D.T.E. 05-27, no longer exists once new cast-off rates are established and, therefore, it is hereby terminated.

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19 The Department will not address the issue of whether a utility may request a new rate plan term in conjunction with an increase in base rates. This issue is not before us in this proceeding. Bay State did not propose a new rate plan with new cast-off rates. Rather, Bay State seeks to continue its existing PBR plan for the remainder of the ten-year term approved in D.T.E. 05-27.

Moreover, we find that the Company's PBR plan is not working as intended. Although the Company advocates for the continuation of the PBR plan or, at least the continued applicability of the earnings sharing mechanism, exogenous cost recovery mechanism and the PBR rate adjustment formula, it is evident that Bay State's experience with the PBR plan has been less than successful. The Company concedes that the PBR plan has failed to provide sufficient revenues to cover the Company's operating and maintenance costs, declining use per customer, and capital investment needs (Exhs. AG-4-6; AG-32-17; Tr. 1, at 165, 168; Tr. 12, at 2099-2100). Additionally, as stated above, the Company has, on several occasions in the past four years, sought relief under the exogenous cost, earnings sharing mechanism, and extraordinary economic circumstances provisions of the PBR plan. See D.P.U. 08-41; D.P.U. 07-89; D.P.U. 07-74; D.P.U. 06-77. The Company provides numerous reasons for the rate plan's substandard performance, such as the historical time frame underlying the construction of PBR, fundamental changes in the utility industry, the lengthy term of the PBR, and capital investment demands (Tr. 1, at 165-168; Tr. 12, at 2104). Regardless of the reasons, the fact remains that the Company has been unable to effectively and efficiently operate within the parameters of the existing PBR plan.

In addition, although the Company identifies various efforts to promote operational efficiency and/or reduce its costs (see, e.g., Exh. DPU-8-5; Tr. 7, at 992-993), we are not persuaded that the tangible benefits to ratepayers, if any, flowing from the continuation of the PBR plan, including the establishment of new base rates, outweigh terminating the PBR plan. There is nothing in the record to convince us that such initiatives would not have been undertaken absent the PBR (Tr. 7, at 1016). Indeed, the Company is unable to quantify any significant cost savings and benefits to ratepayers associated with its PBR plan (Exh. DPU-8-5; Tr. 7, at 976, 993). See D.T.E. 05-27, at 399-400 (recognizing a ten-year PBR term as reasonable for Bay State to "implement long-term business strategies that could produce significant cost savings and other benefits to ratepayers and shareholders").

3. Conclusion

Based on the foregoing, the Department concludes that Bay State's PBR plan is terminated as a result of the establishment of new base rates. We find, therefore, that the earnings sharing mechanism, exogenous cost recovery mechanism and the PBR rate adjustment formula that were part of the ten-year PBR plan are terminated as well. Accordingly, the Department rejects the proposed continuation of Bay State's PBR plan. We will address the merits of the Company's claimed revenue deficiency in the various sections below.

III. REVENUE DECOUPLING PROPOSAL

A. Description of the Company's Proposal

1. Introduction

Pursuant to the Department's directive in D.P.U. 07-50-A, the Company filed a proposed revenue decoupling adjustment clause ("RDAC") tariff, M.D.P.U. No. 105 (Exh. BSG/DPY-1, Sch. DPY-1-5). The Company subsequently filed a revised RDAC tariff (Exh. BSG/DPY-1, Sch. DPY-1-5 (Rev.); Tr. 2, at 220-221).[20] The proposed revised RDAC

[20] The revised RDAC tariff corrected for certain errors identified in the process of responding to the information requests of the Attorney General and the Department (Company Letter dated July 6, 2009; Exhs. DPU-2-26; AG-7-7; Tr. 2, at 220-221). For clarity, our discussion of the proposed RDAC tariff will reference this revised

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SCHEDULE A TO

DECISION

DATED FEBRUARY 11, 2008

ENBRIDGE GAS DISTRIBUTION INC.

EB-2007-0615

REVISED SETTLEMENT AGREEMENT

SETTLEMENT AGREEMENT

FEBRUARY 4, 2008

TABLE OF CONTENTS

I. INTRODUCTION

This Settlement Agreement ("Agreement") is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the EB-2007-0615 application ("Application") of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") for an order or orders approving a revenue per customer cap as the Incentive Regulation ("IR") framework to be used for the purpose of setting of rates for the period from January 1, 2008 to December 31, 2012 ("IR Plan").

II. SETTLEMENT CONFERENCE

Procedural Order No. 5, dated August 31, 2007, provided for a Settlement Conference. A Settlement Conference was accordingly held from December 6 to December 18, 2007 and from January 2 to January 17, 2008, in accordance with the Board's *Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines") in connection with the Application. This Agreement arises from the Settlement Conference.

Enbridge and the following intervenors (collectively, the "Parties"), as well as the Board's technical staff ("Board Staff"), participated in the Settlement Conference:

Association of Power Producers of Ontario ("APPrO")
Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Consumers Council of Canada ("CCC")
Coral Energy Canada Inc. ("Coral/Shell Energy")
Energy Probe Research Foundation ("Energy Probe")
Green Energy Coalition ("GEC")
Industrial Gas Users Association ("IGUA")
Jason F. Stacey
City of Kitchener ("Kitchener")
London Property Management Association ("LPMA")
Ontario Association of Physical Plant Administrators ("OAPPA")
Pollution Probe
Power Workers Union ("PWU")
School Energy Coalition ("SEC")
Sithe Global Power Goreway ULC ("Sithe")
City of Timmins ("Timmins")
TransAlta Cogeneration L.P. and TransAlta Energy Corp. ("TransAlta")
Vulnerable Energy Consumers Coalition ("VECC")
Wholesale Gas Service Purchasers Group ("WGSPG")

L-1-1	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 6, 2007 Report)
L-1-2	Rate Adjustment Indexes for Ontario's Natural Gas Utilities (PEG November 20, 2007 Report)
L-5-1	IGUA Evidence

6 Z FACTOR

6.1 What are the criteria for establishing Z factors that should be included in the IR plan?

- **Complete Settlement:**

Z-Factor Criteria

The Parties agree that Z factors generally have to meet the following criteria:

(i) the event must be causally related to an increase/decrease in cost;

(ii) the cost must be beyond the control of the Company's management and is not a risk in respect of which a prudent utility would take risk mitigation steps;

(iii) the cost increase/decrease must not otherwise reflected in the per customer revenue cap;

(iv) any cost increase must be prudently incurred; and

(v) the cost increase/decrease must meet the materiality threshold of $1.5 million annually per Z factor event (i.e., the sum of all individual items underlying the Z factor event).

ROE Methodology

If a proceeding is instituted before the Board, before the term of this IR Plan expires, in which changes to the methodology for determining the ROE is requested, then all Parties, including Enbridge, will be free to take such positions as they consider appropriate with respect to that proceeding. Enbridge may apply to the Board to institute such a proceeding should a change in the methodology for determining return on equity be approved or adopted by the Board. If the Board determines that a change in methodology is appropriate, Enbridge or any other Party in this proceeding, may apply for determination of whether or not that change should be applied to Enbridge during the term of the IR Plan. All Parties, including Enbridge, would be free to take any position on that application, including without limitation:

(i) opposing the application of the change in methodology to Enbridge during the IR Plan;

(ii) proposing offsetting or complimentary adjustments to Enbridge's IR Plan, revenue or rates that the Party considers appropriate to the circumstances; and

(iii) taking any other positions as the Party may consider relevant and the Board agrees to hear.

If, after hearing such application, the Board determines that such methodology change should be treated as a Z factor, the Parties agree that such decision will operate on a prospective basis only.

NGEIR

The Parties agree that any rate impacts specifically identified in any order of the Board related to certain intervenors' petitions to the Lieutenant Governor in Council in connection with the Board's NGEIR Decision (EB-2006-0551) or related to the Board's disposition of Enbridge's pending natural gas storage allocation proceeding (EB-2007-724-725) will be treated as Z factors, subject to the materiality threshold.

Changes in Tax Rules and Rates

With respect to changes in the annual amount of forecast taxes for Enbridge that result from future changes to federal and/or provincial legislation and/or regulations thereunder (including changes in federal tax rates and calculation rules announced in March and October of 2007), the Parties agree as follows:

(i) amounts calculated in association with expected tax rate and rule changes with respect to corporate income tax rates, provincial capital tax rates and capital cost allowance ("CCA") rates that occur within the term of the IR plan, based upon the 2007 Board Approved base level benchmarks embedded in rates, will be shared equally between ratepayers and the Company; Appendix D is a schedule that shows the estimated impact of expected changes in tax rates for the period 2008-2012; the 50% share that is for the account of ratepayers, pursuant to the settlement of this issue, is shown at line 45; Appendix C includes a schedule that sets out the estimated distribution revenue impacts for the years 2008-2012; the same tax impact that is shown at line 45 of Appendix D is also shown at line 10 of the schedule included in Appendix C;

(ii) associated with the sharing described above is a true-up variance account mechanism (the Tax Rate and Rule Change Variance Account or "TRRCVA") relating to changes in actual rates and rules which are different from those proposed and embedded in rates; in the event that the future tax rates and rules are not as currently expected, the Company will calculate the appropriate amounts which should be shared between ratepayers and the Company and record the appropriate variance in the variance account to be returned to or collected from ratepayers; this true-up will occur annually, along with any associated required change to ongoing future rates; and

(iii) the settlement of this issue does not prejudice and is in no way determinative of the position that parties may wish to take on this issue in other proceedings; moreover, the settlement of this issue is not intended to be an expression of the principles and rules that should govern the Board's disposition of this issue outside the framework of this Agreement.

The Parties, who are in agreement with the settlement of this issue, have compromised their individual views with respect to the extent which the impact of changes in federal tax rates and calculation rules are properly characterized as a Z factor. These compromises have been in order to reach an agreement on this issue.

- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except:

  (i) SEC who agrees with the settlement except for the settlement of the tax change issue, on which it takes no position; and

  (ii) the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.

- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-5-1	Deferral and Variance Accounts
I-1-20	Board Staff Interrogatory 20
I-3-29 to 32	CCC Interrogatory 29 to 32
I-7-1 and 17	LPMA Interrogatories 1 and 17
I-11-60 to 61	SEC Interrogatories 60 to 61

JTB.23	SEC Undertaking 23 to EGD
JTB.42 and 43	IGUA Undertakings JTB.42 and 43 to PEG
L-3-1	CCC/VECC/City of Kitchener Evidence of Dr. Loube
L-5-1	IGUA Evidence

6.2 Should there be materiality tests, and if so, what should they be?

- **Complete Settlement:** See Issue 6.1
- **Evidence:** The evidence that is relevant to this issue includes the following:

B-1-1	Incentive Regulation Proposal
I-7-2	LPMA Interrogatory 2
JTB.2	IGUA Undertaking 2 to EGD
JTB.42	IGUA Undertaking JTB.42 to PEG
L-5-1	IGUA Evidence

7 NATURAL GAS ELECTRICITY INTERFACE REVIEW (NGEIR) DECISIONS

7.1 How should the impacts of the NGEIR decisions, if any, be reflected in rates during the IR plan?

- **Complete Settlement:** The Parties agree, subject to the reservations of rights described in the settlement of 6.1 of this Agreement, that Enbridge will implement the Board's final NGEIR decisions, where relevant and applicable, in accordance with any Board direction in this regard and in accordance with existing Board-approved cost allocation and rate design principles.
- **Participating Parties:** All parties participated in the negotiation and settlement of this issue except Coral/Shell Energy.
- **Approvals:** All participating Parties accept and agree with the settlement except the following Parties who take no position on the issue: GEC, Kitchener, Pollution Probe, PWU, Timmins and Transalta.
- **Evidence:** The evidence in support of the settlement of this issue includes the following:

B-1-1	Incentive Regulation Proposal
B-4- 1	Y Factor – Capital
B-4-2	Y Factor – Other
B-6- 1	Rate Filing Process and Report Requirements
I-11-62	SEC Interrogatory 62
I-16-2 to 4	TransAlta Interrogatories 2 to 4

BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #1

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.1

Has PEG ever recommended or supported an IR plan that treated OM&A separate from capital in testimony or an expert report? If so, please provide the docket number, jurisdiction, date, and copies of all PEG testimony and/or expert reports.

RESPONSE

PEG has testified four times on IR plans that treated OM&A costs separately from capital costs:

1. Hawaiian Electric Company
   Docket Number 2008-0274
   Jurisdiction Hawaii
   Direct testimony January 2009

2. Boston Gas/National Grid
   Docket Number was DPU 10-55
   Jurisdiction Massachusetts
   Direct testimony April 2010, rebuttal testimony July 2010

3. Gaz Metro
   Docket Number R-3693-2009
   Jurisdiction Quebec
   Direct testimony March 2011

4. Central Maine Power
   Docket Number 2013-00168
   Jurisdiction Maine
   Direct testimony May 2013

Copies of the testimony and associated expert reports are attached.

Witness: Dr. Lawrence Kaufmann, PEG

Filed: 2014-01-23
EB-2012-0459
Exhibit TCU1.7
Page 1 of 2
Plus Attachment

BOARD STAFF RESPONSE TO UNDERTAKING OF EGDI

UNDERTAKING TCU1.7

REF: Tr.1 p32

DR. KAUFMANN TO PROVIDE WRITTEN MATERIALS THAT SUPPORT HIS VIEW REGARDING THE RELATIONSHIP BETWEEN FROST HEAVE AND DIFFERENT GAS DISTRIBUTION PIPE MATERIALS

RESPONSE

Please see the attached February 2012 White Paper "Distribution Pipeline System Integrity Threats Related to Cold Weather," prepared by Kiefner & Associates Inc. In the Summary and Conclusions section of this paper (pp. 1-2), they write:

> "Cold weather-related incidents have occurred in gas distribution systems, gas transmission systems, and hazardous liquid transmission systems. By far the most common cause of such incidents is frost heave, acting on buried pipe...All types of pipe materials found in distribution service have been affected, however piping with certain attribute appear to have higher-than-average susceptibility. These are:
>
> - Cast iron pipe
> - Pipe of unknown material type
> - Steel pipe installed prior to 1950
>
> Integrity Management (IM) principles require that the operator consider integrity threat interaction. Frost heave or snow load might be readily tolerated by some materials or piping systems in sound condition, while low-ductility materials or pipe joints made by vintage techniques may remain reliable absent certain outside forces, however, when these circumstances exist simultaneously the likelihood of a failure is significantly greater. Systems of the type listed above in locations susceptible to frost heave therefore represent potential interacting-threat situations.
>
> Piping systems having the attributes listed above and located in areas known or suspected to be susceptible to frost heave or thaw settlement should be identified and considered for condition monitoring or mitigation

Witness: Dr. Lawrence Kaufmann, PEG

activities…Mitigations could include but are not limited to: replace iron pipe, unknown-material pipe, and threaded steel pipe, with plastic or welded steel pipe in locations known or suspected to be susceptible to frost heave."

This summary discussion, and the analysis that follows, supports Dr. Kaufmann's opinion that the consequences of frost heave for system integrity and gas leaks are associated more with cast iron and bare steel gas distribution main than plastic/ polyethylene main. In fact, the authors say that actions for mitigating the effects of frost heave on distribution systems include replacing cast iron and threaded steel pipe with plastic pipe.

Witness: Dr. Lawrence Kaufmann, PEG

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KIEFNER WHITE PAPER, FEBRUARY 2012

Distribution Pipeline System Integrity Threats Related to Cold Weather

MJ Rosenfeld, PE and M Van Auker

INTRODUCTION

Cold weather can produce threats to the integrity of distribution pipeline systems. Integrity management (IM) concepts required an operator to identify integrity threats as a necessary step to prioritizing integrity assessments, and developing mitigations. This report discusses the most common integrity threats caused by cold weather and identifies the attributes of the most susceptible systems. This information should enable a gas distribution system operator to develop appropriate decision processes to address cold weather risks in the context of its distribution IM program.

SUMMARY AND CONCLUSIONS

Cold weather-related incidents have occurred in gas distribution systems, gas transmission systems, and hazardous liquid transmission systems. By far the most common cause of such incidents is frost heave, acting on buried pipe. However, a large number of less-frequent incident scenarios related to cold weather have been described in PHMSA's reportable incident database, affecting both buried and above-ground installations. All types of pipe materials found in distribution service have been affected, however piping with certain attributes appear to have higher-than-average susceptibility. These are:

- Cast iron pipe
- Pipe of unknown material type
- Steel pipe installed prior to 1950

Applus RTD

IM principles require that the operator consider integrity threat interaction. Frost heave or snow load might be readily tolerated by some materials or a piping system in sound condition, while low-ductility materials or pipe joints made by vintage techniques may remain reliable absent certain outside forces, however, when these circumstances exist simultaneously the likelihood of a failure is significantly greater. Systems of the type listed above in locations susceptible to frost heave therefore represent potential interacting-threat situations.

Piping systems having the attributes listed above and located in areas known or suspected to be susceptible to frost heave or thaw settlement should be identified and considered for condition monitoring or mitigation activities. While frost heave was responsible for the largest number of incidents, other causes have also been identified, including snow and ice falls from rooftops, confined freezing of water trapped in components, or build-up of ice where standing water accumulates around risers or under low-mounted above-ground components.

Condition monitoring could involve a range of activities, including but not limited to:

- periodic visual site inspection during cold weather months by someone qualified to recognize evidence of frost heave or thaw settlement;
- examination of piping buried above the frost line for evidence of deflection at joints during routine excavations;
- visual inspection of sites for frozen standing water around risers or under equipment mounted low to the ground.

Mitigations could include but are not limited to:

- replace iron pipe, unknown-material pipe, and threaded steel pipe with plastic or welded steel pipe in locations known or suspected to be susceptible to frost heave;
- remediate drainage or soil conditions that promote frost heave at susceptible sites;
- correct drainage conditions that promote accumulation of standing water around risers or under low-mounted equipment;
- drain trapped moisture from equipment during routine maintenance or inspections.

ANALYSIS

Cold weather effects on pipeline systems are typically classified as time independent (i.e., randomly occurring) threats. A failure caused by a time independent threat is typically incident driven such as in the case of third party damage, versus a time dependent threat which can involve deterioration of the pipeline component over time by some mechanism such as corrosion or cracking. With exposure to cold weather, the pipeline system can be threatened by a number of circumstances that can cause excessive stress or strain to produce a failure in the pipeline components. Some of these threats include frost heave, loads on pipeline components due to snow and ice accumulation, erosion due to snow and ice melts, thermal stresses due to extreme cold temperatures, and confined expansion of freezing water within components.

Causes of Distribution System Incidents

The Pipeline Hazardous Material Safety Administration (PHMSA) has collected pipeline failure data for distribution pipeline operations in the United States. This data shows that pipeline failures due to natural forces account for approximately 5.8% and 5.9% of the failures reported in 2010 and 2011, shown in Figure 1.[1]

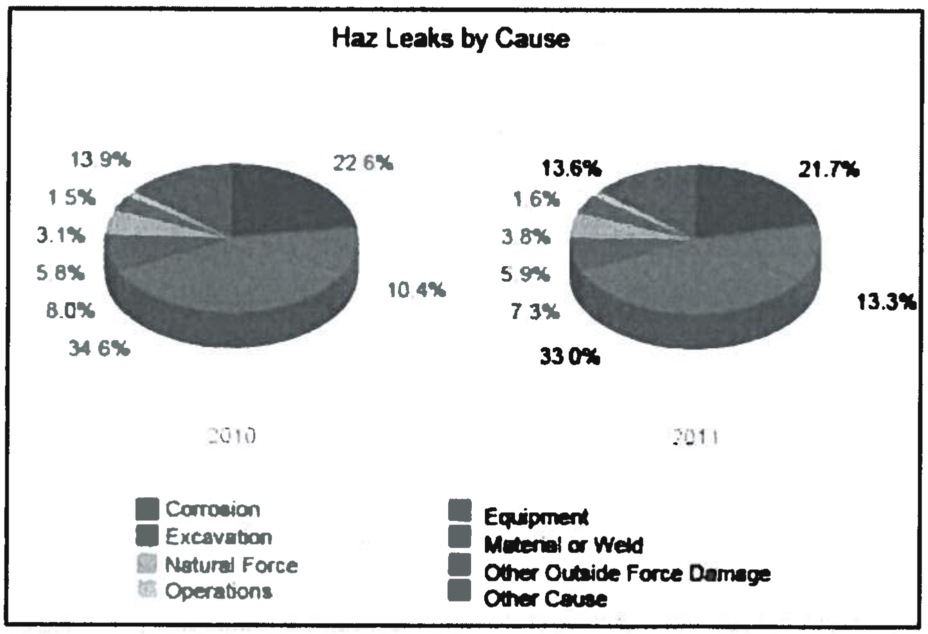

Figure 1. Hazardous Leaks on Distribution Systems by Cause

[1] www.phmsa.dot.gov

The natural force damage category includes incidents resulting from earth movement, earthquakes, landslides, subsidence, lightning, heavy rains/floods, washouts, flotation, mudslides, scouring, temperature, frost heave, frozen components, high winds, and weather events including cold weather. Closer analysis of the PHMSA data for leaks caused by natural force damage provides a better understanding of how cold weather can impact the integrity of distribution pipeline systems. The PHMSA data included 120 leak incidents on distribution systems reported to be associated with cold weather failure as a cause, Figure 2. The failure cause most frequently reported was frost heave, followed by failures due to snow accumulation and movement.

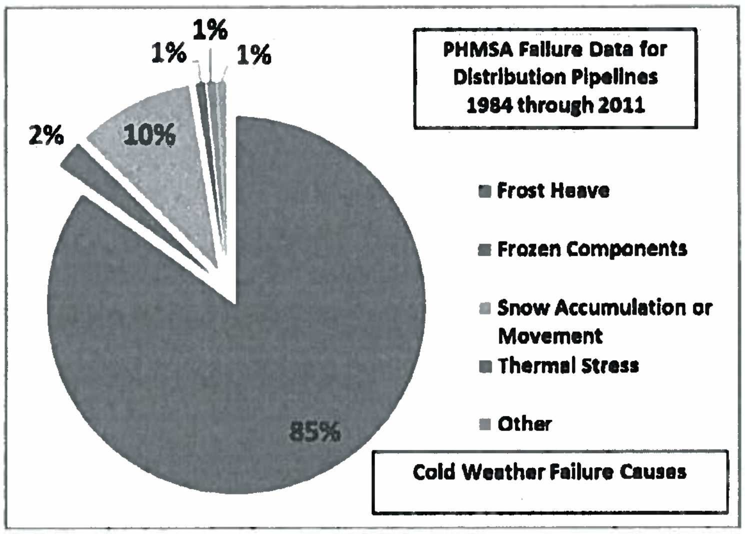

Figure 2. PHMSA Cold Weather Failure Causes

About Frost Heave

Frost heave results from ice forming beneath the surface of soil during freezing conditions in the atmosphere. The ice grows in the direction of heat loss (vertically toward the surface), starting at the freezing front or boundary below the soil surface. It requires an unfrozen water supply (usually below the frozen soil) to keep feeding the ice crystal growth. The growing ice is restrained by overlying soil, which applies a load that limits its vertical growth and promotes the formation of a lens-shaped body of ice within the soil. The growth of ice lenses continually consumes the rising water at the freezing front. The soil through which water passes to feed the formation of ice lenses must be sufficiently porous to allow capillary action, but not so porous as to break capillary continuity. Such soil is referred to as "frost heave susceptible". [2] Two common criteria for susceptibility are more than 10% of soil particles being finer than 0.075 mm, or more than 3% of particles being finer than 0.020 mm. Considering particle size alone does not account for the effects of variables such as the presence of ground water or the presence of dissolved salts or other substances which can alter the freezing state. A more comprehensive test[3] would be required in the event that precise information about susceptibility is required. Visible vertical displacement of the ground surface or effects on pavement would be consistent with the occurrence of frost heave. The resulting earth movement associated with frost heave can be significant and can impose strain on pipeline components impacted by the movement.

The primary structural integrity impact to pipeline systems as a result of frost heave is excessive longitudinal stress due to the displacement strain imposed by the earth movement. The likelihood of a failure due to frost heave may be increased when other threats exist such as circumferential stress-corrosion cracking or low-quality girth welds or threaded connections. The susceptibility of a pipeline system to damage by frost heave can be assessed by considering some key factors.

- The soil type in which the pipeline is laid. Silty and loamy types of soils would be an example of frost susceptible soil while clay or clean sand and gravel are examples of soils not susceptible to frost heave.
- The depth that a pipeline is buried. Lines buried below the frost line of a geographical area would be less susceptible to impact from frost heave since the earth movement is typically in the vertical direction and occurs above the frost line.
- Pipeline material and specification, or method of construction. The ability of a pipeline to withstand high longitudinal stress or strain may affect its likelihood for failure due to the impact of frost heave.
- The flexibility of above ground installations in frost heave susceptible areas.

The combinations of factors discussed above indicate that failure due to frost heave and other cold-weather effects represents probable interacting threat circumstances.

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[2] Andersland, O.B. and Ladanyi, B., Frozen Ground Engineering, 2nd Ed., ASCE and J. Wiley & Sons Inc., 2004.
[3] ASTM D5918, "Standard Test Methods for Frost Heave and Thaw Susceptibility of Soils", 2006.

Interacting threats are understood to occur where the probability of failure due to specific factors is significantly greater than the sum of individual probability of failure (as a proxy for "risk") from the factors occurring independently. Frost heave or snow loads, while not desirable, may be readily tolerated by ductile materials and or better-quality joints between pipes. Likewise, low-ductility materials or artifacts of vintage pipe construction technology, while not optimal, may not present a threat where normal internal pressure is the only significant load. However, certain combinations of materials in conjunction with cold weather effects may create a more acute situation than either set of circumstances do separately. This is demonstrated in the following analysis of data to identify specific attributes of piping that appear to enhance susceptibility to cold weather effects, as evidenced by high incident rates relative to the representation in the pipeline mileage fleet.

Cold Weather Failure Data

Analysis of the PHMSA reported incident data provides additional insight to the types of distribution systems that have reported failures due to cold weather effects. The data was evaluated in terms of:

- Location
- Era of installation
- Affected material
- Affected component
- Size of pipe

The results of the data analysis are discussed below. We focused on reported incident data for natural gas distribution systems, which includes mains and services. We also reviewed incident data for gas transmission systems and hazardous liquid transmission systems. With the exception of certain features unique to distribution systems (e.g. cast iron or plastic piping), the data from incidents in those systems told a similar story to the data from gas distribution systems. However an analysis of the non-distribution system data is not presented here.

The reporting interval for the data we reviewed was 1984 through 2011. During that time there were 120 incidents associated with cold weather, 95 of which were in pipe.

Location

A significant majority of the incidents affected buried pipe or components, Figure 3. This suggests that the predominant cause is related to frost heave or thaw settlement. A large proportion of those underground were also reported as under pavement.

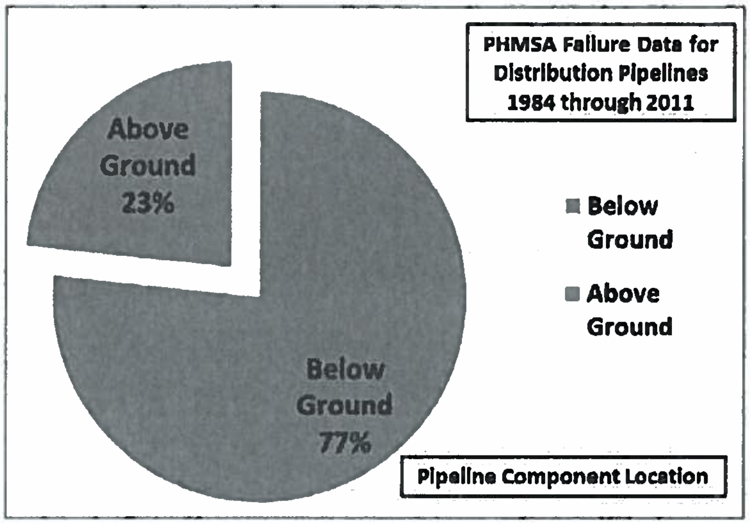

Figure 3. Cold Weather Incidents by Location

Era of Installation

The reported incidents due to cold weather were fairly evenly distributed over 20-year segments of time representing different periods of installation, from 1910 to the present, Figure 4, except that the era from 1950 to 1969 had approximately twice as many incidents as other eras.

It was thought that the larger number of incidents for 1950-1969 vintage pipe may reflect the large proportion of pipe in service installed during that time. In order to understand whether certain vintages of pipe have high or low susceptibility, the proportion of incidents attributed to specific decades of installation were compared to their representative proportions of mains miles in service nationally, listed in Table 1.

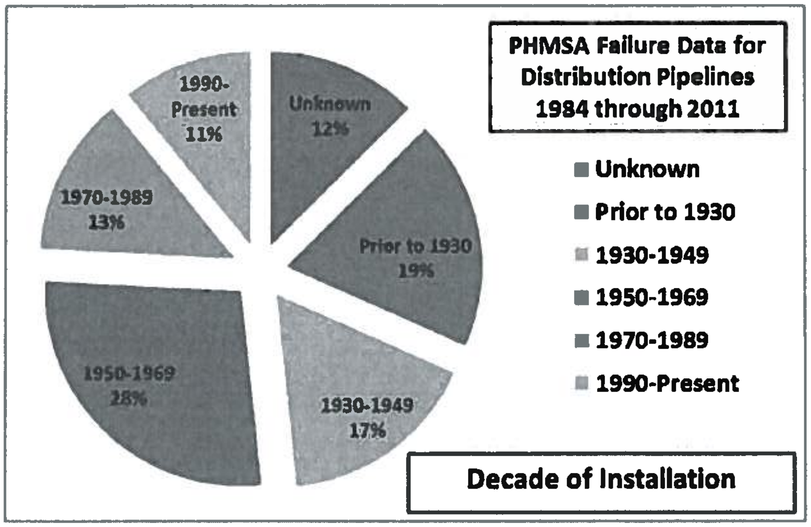

Figure 4. Cold Weather Incidents by Era of Installation

Table 1. Cold Weather Incidents and Mains Mileage by Installed Decade

Installed Decade	Incidents	% Incidents	Mains Miles	% Miles	Relative Rate
Unknown[(a)]	15	12.5%	84,736	7.0%	1.784
Pre-1940	33	27.5%	68,350	5.7%	4.866
1940 – 1949	10	8.3%	25,979	2.1%	3.880
1950 -1959	17	14.2%	107,757	8.9%	1.590
1960 – 1969	16	13.3%	196,394	16.2%	0.821
1970 – 1979	9	7.5%	131,311	10.9%	0.691
1980 – 1989	7	5.8%	155,571	12.9%	0.454
1990 – 1999	4	3.3%	232,657	19.2%	0.173
2000-Present	9	7.5%	206,731	17.1%	0.439

(a) Unknown includes both unreported and undocumented

A high susceptibility would be indicated by the ratio of the proportion of incidents normalized to the proportion of mains mileage being greater than 1.0; similarly, low susceptibility would be indicated by a ratio less than 1.0. This ratio is presented in Table 1 under the "Relative Rate" heading and is shown in Figure 5.

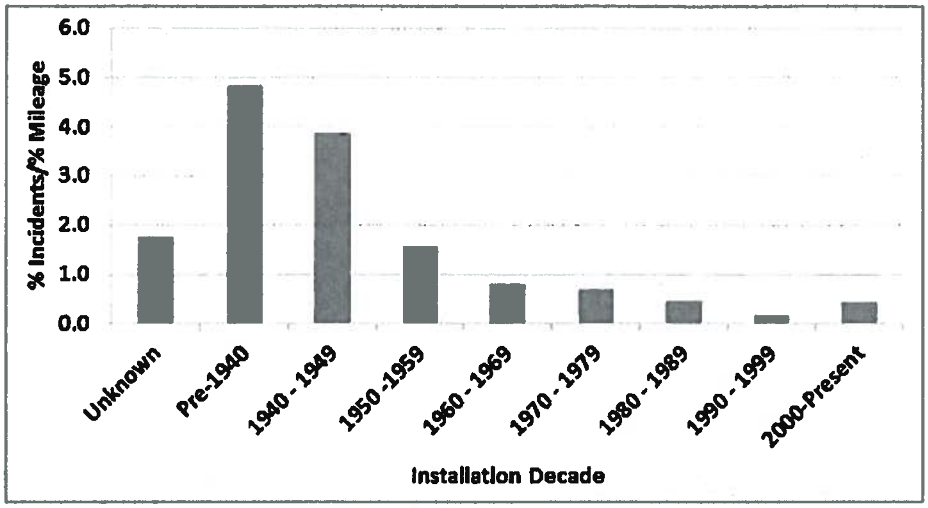

Figure 5. Normalized Susceptibility by Installed Decade

The results show that pipe installed earlier than 1950 have disproportionately high susceptibility to problems from cold weather. This is also true for pipe of unknown vintage, and pipe installed after 1950 but before 1960, but not to the extent of the pre-1950 pipe. The greater susceptibility of pre-1950 pipe is postulated to be due to two key factors. One would be the generally poor low-temperature ductility of the steels of the era which tended to have high carbon content, high sulfur content, or large-grained microstructures. The other would be the methods used to join pipe in that era, including early electric arc welds, acetylene welds, couplings, or threaded collars, all of which could have limited strength or ductility. Systems newer than 1960 exhibited comparatively lower susceptibility due to better pipe products and better quality girth welds.

Affected Materials and Components

Identified materials associated with the cold weather incidents were steel, plastic, iron, other, and unknown.[4] The systems reporting the highest number of failures were constructed of steel and cast or wrought iron, representing 40% and 42% of the incidents, respectively. Plastic and other materials represented low numbers of instances, representing 7% and 8%, respectively.

[4] "Unknown" includes the category of not reported on the F7100.1-1 annual data reporting form, which may or may not mean that the information is unknown by the operator. The material is supposed to be specified by the operator if "other" is selected.

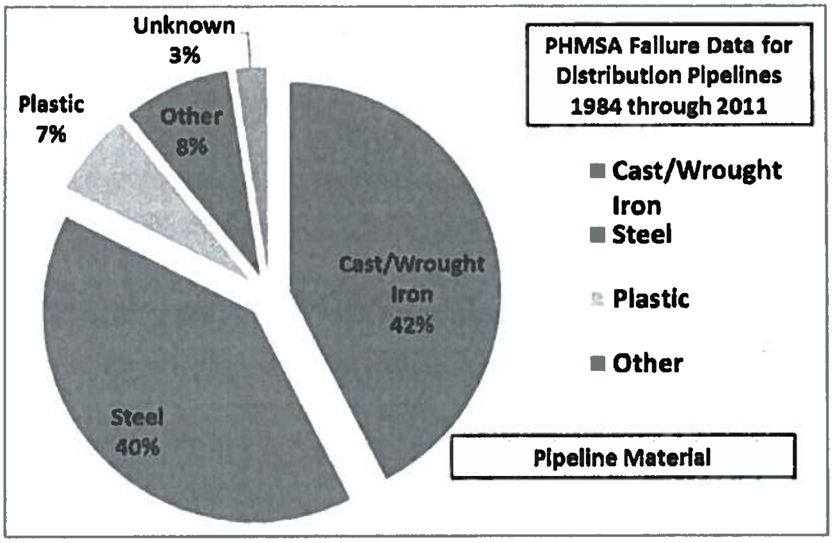

Figure 6. Cold Weather Incidents by Affected Material

However, these numbers do not appropriately describe relative susceptibility. Table 2 below lists the numbers of cold weather incidents and the number of mains miles by material type. Iron and other or unknown materials comprise very small proportions of the total mains mileage in service. The ratio of the proportion of incidents normalized to the proportion of representative miles shows extremely high susceptibility for those materials compared with steel or plastic. Steel is seen to be significantly higher than plastic, but still well below iron or the other and unknown material categories.

Table 2. Cold Weather Incidents and Mains Mileage by Material Type

Material	Incidents	% Incidents	Mains Miles	% Miles	Relative Rate
Cast/Wrought Iron	51	0.425	36,247	0.030	14.18
Steel	48	0.400	551,228	0.456	0.88
Plastic	8	0.067	620,610	0.513	0.13
Other & unknown	3	0.025	1,402	0.001	21.57

A majority of reported cold weather incidents, 58%, occurred in mains while service lines were reported in 19% of the cases, Figure 7. Meters and regulators were associated with 18% of the failures reported with most identified by causes related to snow and ice accumulation or frozen components.

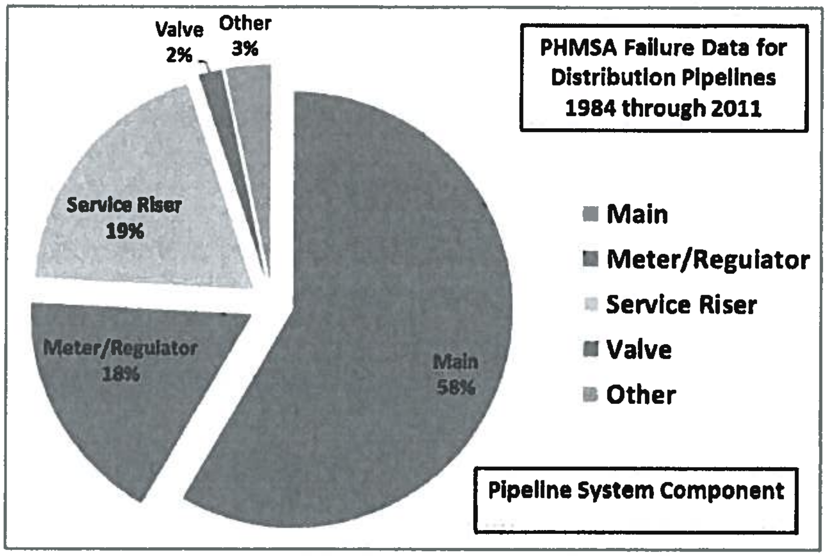

Figure 7. Cold Weather Incidents by Component

Cold Weather Incident Causes and Consequences

Cause Scenarios

A majority of the distribution systems associated with cold weather cited natural forces or outside force damage, and frequently frost heave. Other less often cited scenarios included the following, or variants thereof:

- Heavy snow or ice loads shedding off rooftops
- Damage from floating ice during flooding
- Damage from falling trees caused by ice accumulation
- Icing causing equipment or device malfunction

The PHMSA database often does not delve into the complexities of some incidents, which can only be discovered in the course of a failure investigation. Most incident reports are completed soon after an incident and before such an investigation can be completed. We are aware of a small number of incidents of near-neutral-pH stress-corrosion cracking in the threaded pipe ends of service lines, probably caused in part by frost heave or thaw settlement.[5] Only one of those incidents is identified in the PHMSA database as cold weather-related, specifically frost-heave (so the others are not

[5] A stress concentration is present at the root of the thread, acting on the axial stress induced by frost heave or settlement. A conducive environment must also be present, which might occur where a threaded joint holds moisture, oxygen in the crevice is consumed creating an anaerobic condition, and pH is in the neutral range due to lack of cathodic protection.

counted in this survey), and none are identified therein as having been affected by environmental cracking. We have also seen several incidents involving small valve bodies that fractured. These were believed to have been caused by the constrained expansion of frozen water trapped inside the valves although the direct evidence was gone (the ice was melted). We are also aware of a few incidents where the volumetric expansion of freezing water at the ground surface caused excessive reaction forces on branch connections or components. These examples illustrate the potential complexities of integrity threats associated with cold weather, or even proving that cold weather was the cause. We believe that cold weather related incidents are likely to be underreported.

Consequences

Most incidents were reported as leaks, frequently as separations of couplings or threaded joints. The isolated incidents identified as ruptures are thought to have been erroneously reported. Of the 120 distribution system incidents from 1984 through 2011, the following consequences occurred:

- 5 incidents caused 8 fatalities;
- 33 incidents caused 50 injury cases.

None of the cold weather related incidents reported for gas transmission or hazardous liquid transmission pipelines caused fatalities or injuries. This underscores the unique risk factors associated with distribution systems, namely the prevalence of gas migration paths and proximity to buildings.

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EGDI [Concentric] to provide the sum of capital costs plus OM&A costs for each company in the sample and for the industry as a whole (the twenty five companies) and for Enbridge, and divide by total customers for 2010 and 2011.

RESPONSE

Preliminary comments:

Using TFP-based costs[1] per customer for a single year (e.g., 2010 or 2011) to benchmark the performance of individual distributors or groups of distributors is inappropriate for the same reasons that using the growth in TFP indexes for a single year to measure the productivity of individual distributors or groups of distributors is inappropriate. To account for year-to-year volatility in the components of a TFP index, it is widely accepted that TFP results must be evaluated over a sufficiently long period, such as ten years, to identify long term trends in productivity.

In addition, it is common practice to benchmark distributors according to measures of costs per customer and costs per volume of gas delivered to customers. In fact, measures of costs per volume may be the better approach to benchmark distributors because costs per volume provides a broader view of aggregate costs in relation to total sales and transport volumes not captured on a per customer basis.

Lastly, TFP-based costs for any distributor in any year are not the same as the revenue requirement for that distributor in that year[2], mainly because TFP-based capital costs

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1 As used in this response, "TFP-based costs" are the costs that were calculated for Concentric's TFP analysis, Exhibit A2, Tab 9, Schedule 1, Pages 95 – 123.

2 TFP-based total costs is calculated as the sum of TFP capital costs, labour, and materials. TFP-based capital costs are a calculated value; capital costs are not reported in a distributor's annual regulatory filing. TFP-based capital costs are the product of TFP-based price of capital and capital quantity. The price of capital is a calculation that includes terms for the cost of capital, depreciation, and capital gains. The capital quantity is also a calculation, based on estimates of the value in constant (real) dollars of each vintage of in-service plant. For Concentric's TFP analysis, TFP-based labour and materials costs for a year are the O&M expenses as reported in a distributor's annual regulatory filing; the sum of TFP-based labour and materials costs is distribution, transmission, and storage O&M expenses, net of pensions and benefits expense. However,

account for economic costs, such as capital gains, that are not reflected in regulatory accounting revenue requirement calculations. Annual bond yields and ROEs that serve as proxies for the cost of capital also vary from those allowed in rates for individual companies.

Total Factor Productivity is measured with an index designed to capture the trends in inputs and outputs for a given company or industry. The assumptions required to estimate total costs, especially for capital, are not designed to determine an absolute measure of cost in a given year. The overall level of TFP-based costs and year-to-year differences in TFP-based costs are significantly impacted by all of these factors. These data must therefore be considered in light of these limitations.

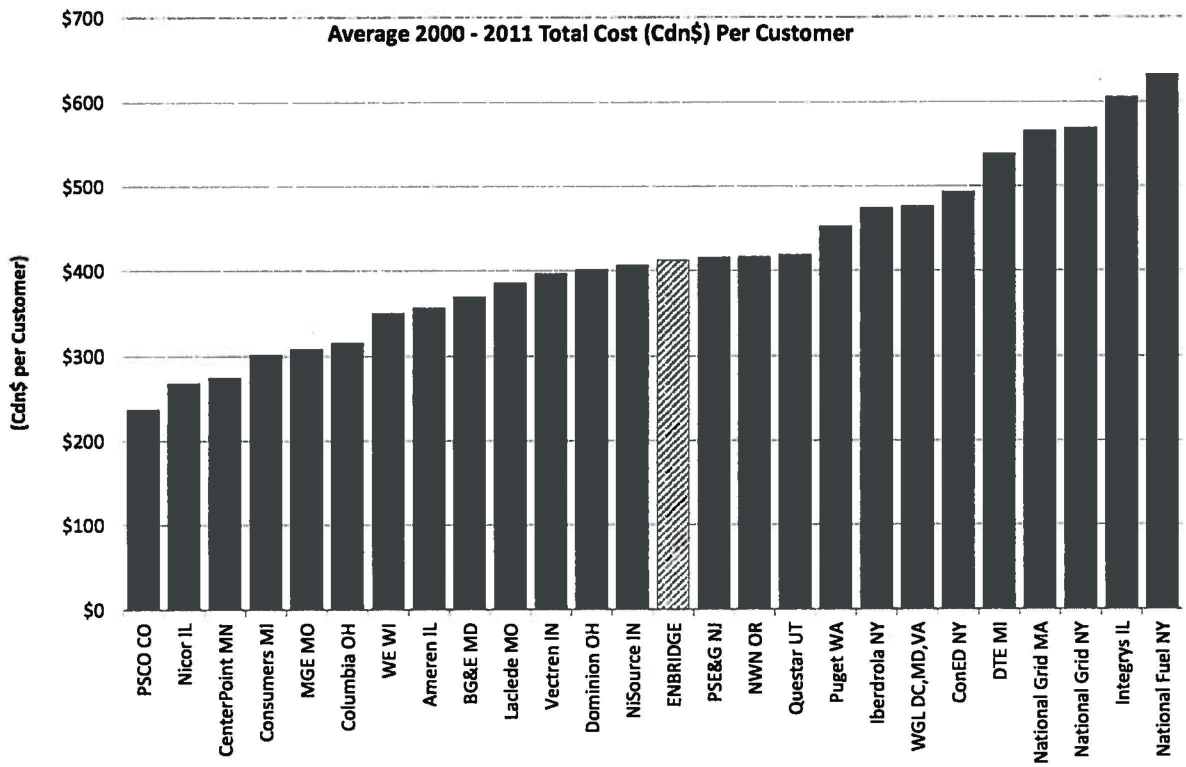
For these reasons, TFP-based costs have been provided for this response for the entire period of Concentric's TFP analysis, 2000 to 2011, and the benchmarking results are expressed as average costs per volume and costs per customer for Enbridge, the 25 Company Industry Study Group, and the seven company Sub-Group for 2000 to 2011.

Analysis and Discussion

The sum of TFP-based capital costs plus OM&A costs, divided by total customers for each of the 25 companies in the sample plus Enbridge, for the study period, 2000 to 2011 is provided in Attachment TCU1.11 page 1; cost data per volume (103m3) is provided in Attachment TCU1.11 page 2.

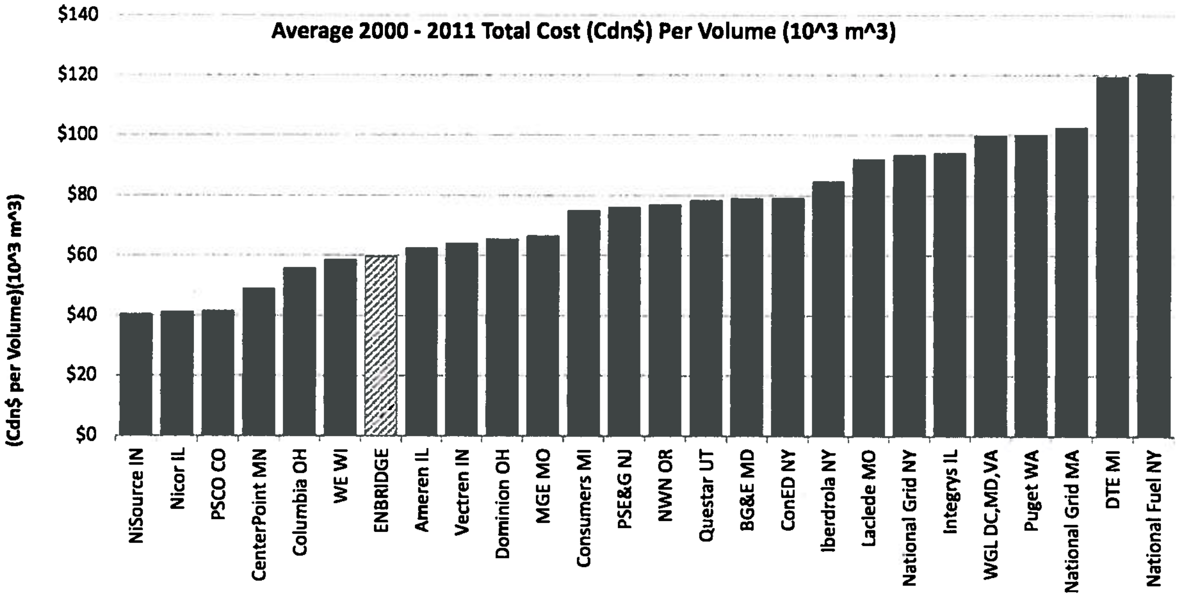
The following Figure 1, Cost per Customer benchmarking analysis, summarizes the average 2000 to 2011 cost per customer results in Attachment TCU1.11 page 1. Figure 1 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the median for the 26 companies.

Figure 1 Benchmarking Analysis: Average Total TFP-based Cost per Customer



The following Figure 2, Cost per Volume benchmarking analysis, summarizes the average 2000 to 2011 cost per volume results in Attachment TCU1.11 page 2. Figure 2 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the separation point between the top and second quartiles for the 26 companies.

Figure 2 Benchmarking Analysis: Average Total TFP-based Cost per Volume (10^3m^3)



The following Figure 3 provides a summary of TFP-based total costs per customer for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period; Figure 4 provides a summary of TFP-based total costs per volume for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period.

Figure 3 Total TFP-based Cost (Cdn$) Per Customer

	Total Cost (Cdn$) Per Customer		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	503	483	416
2001	521	484	364
2002	521	495	463
2003	469	453	442
2004	384	366	357
2005	304	284	381
2006	283	260	412
2007	321	291	351
2008	350	315	374
2009	498	460	406
2010	459	426	463
2011	388	360	515
Average Annual Cost Per Customer			
2000-2011	417	390	412

Figure 4 Total TFP-based Cost (Cdn$) Per Volume (10^3m^3)

	Total Cost (Cdn$) Per Volume (10^3 m^3)		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	78.43	75.88	52.70
2001	91.36	83.91	47.11
2002	89.38	83.88	64.39
2003	81.05	79.01	56.63
2004	71.43	69.54	48.88
2005	57.72	55.88	54.02
2006	57.42	53.33	63.99
2007	61.16	55.45	53.07
2008	66.01	60.24	57.84
2009	98.54	90.22	63.63
2010	91.04	79.43	73.08
2011	74.95	66.20	79.07
Average Annual Cost Per Volume (10^3 m^3)			
2000-2011	76.54	71.08	59.53

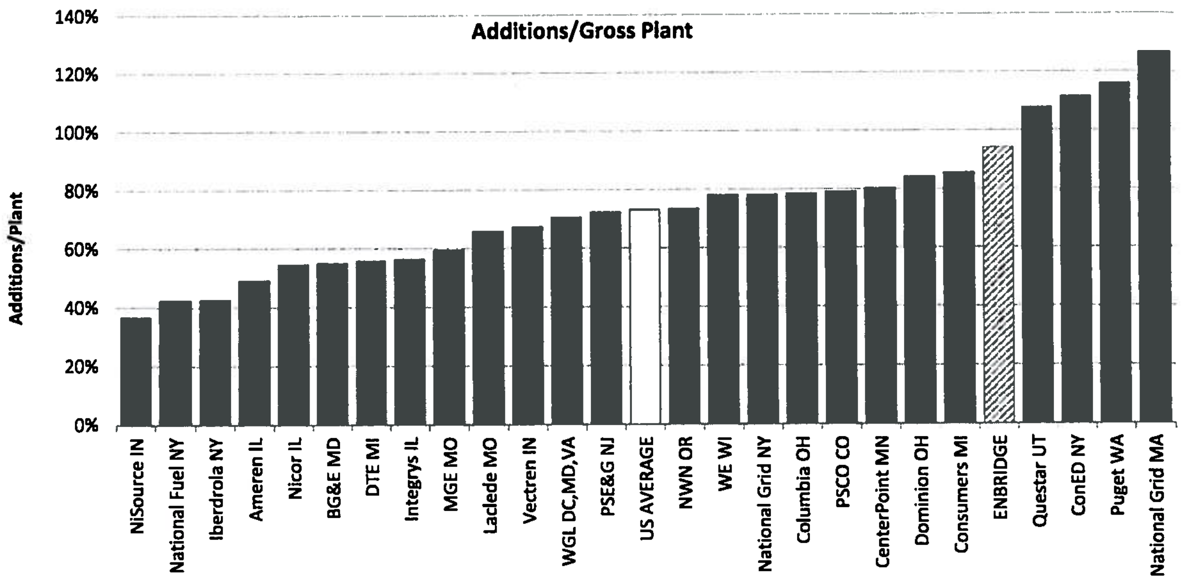
Explanation

The Concentric Incentive Ratemaking Report demonstrates that EGD's 2011 O&M costs per customer and O&M costs per unit of volume are within the lowest – best – quartile, and that the gap between average O&M costs per customer and O&M costs per unit of volume for the study group grew steadily between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 84 to 86.)

The Concentric Incentive Ratemaking Report also demonstrates that EGD's 2011 Net Plant per customer and Net Plant per unit of volume are in the highest and third highest quartiles, respectively, but that the gap between average Net Plant per customer and Net Plant per unit of volume for the study group has been narrowing between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 81 to 83.)

Thus, Enbridge ranks higher (better) on (a) O&M per customer and volume benchmarking than on (b) TFP-based total cost per customer and volume benchmarking because of the effect of Enbridge's capital cost per customer and volume on total cost per customer and volume. As demonstrated by Figure 5, below, only four companies in the study group added plant in recent years at a greater rate than Enbridge.

Figure 5 2001 – 2011 Plant additions as a Percent of 2000 Plant



During the 2001 to 2011 period a large component of plant additions for these 26 companies was (a) replacement of leak-prone pipe[3] and (b) new meters, services, and main extensions to serve new customers. Enbridge's high rate of plant additions is well-understood; Enbridge has been replacing leak prone pipe at a greater rate than other distributors and Enbridge has been adding customers at a greater rate than other distributors.

Specifically, since 2001, Enbridge has replaced approximately 1,000 km of leak-prone pipe; currently, virtually none of Enbridge distribution mains is leak prone. In contrast, most US distributors, including the study group companies, have been replacing leak prone pipe at a slower rate.[4] Also, Enbridge's 2001 to 2011 customer growth rate, 2.6%, was higher than all other companies in the industry study group.

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3 Leak-prone pipe generally includes cast iron, wrought iron and non-cathodically-protected steel mains and services.

4 Related to this point, gas distribution cost models often include a measure of leak prone main in miles as a percent of total distribution mains, to reflect the effect of leak prone pipe on leak repair expense. However, gas distribution cost models should also include a measure to account for the accelerated replacement of leak prone pipe. Other things being equal, a gas distributor that has replaced its leak prone pipe at an accelerated rate will have greater additions to plant in recent years, and therefore higher total costs per customer than distributors that have significant leak prone pipe remaining to be replaced. Similarly, a gas distributor that does not have much leak prone pipe because it recently completed replacing its accelerated leak-prone pipe replacement program will have greater additions to plant in recent years and higher total costs per customer than a gas distributor that has never had much leak prone pipe.

In summary, Enbridge's TFP-based total cost rank must be considered against the limitations of using a TFP index, designed to compare trends in inputs/outputs for the purposes of absolute dollar comparisons. One must also consider company specific circumstances (e.g., accelerated leak prone pipe replacement) that drive capital investment levels.

Total Cost (Cdn$) Per Customer													
													Average
Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2000 - 2011
PSCO CO	297.41	328.97	317.21	285.78	206.09	145.70	134.94	168.62	179.72	285.85	268.44	221.19	236.66
Nicor IL	314.64	323.29	331.60	297.31	248.74	183.16	178.16	203.37	233.52	339.89	312.22	248.53	267.87
CenterPoint MN	329.75	345.77	343.98	312.74	248.91	203.17	187.27	221.69	237.36	320.55	283.08	255.16	274.12
Consumers MI	312.59	342.75	376.84	337.81	288.59	239.06	201.49	232.59	255.11	376.66	346.94	303.65	301.17
MGE MO	322.73	369.14	344.20	337.99	281.40	202.47	195.38	245.25	283.10	402.79	379.98	327.10	307.63
Columbia OH	430.98	388.52	321.49	292.30	252.67	223.95	232.77	267.66	297.55	416.89	372.76	284.46	315.17
WE WI	429.82	423.02	442.76	388.16	315.30	235.06	235.33	255.27	304.78	415.36	410.64	344.23	349.98
Ameren IL	428.38	451.98	464.80	403.70	318.44	233.38	254.25	282.04	311.01	429.11	382.34	311.38	355.90
BG&E MD	440.94	442.42	445.28	387.55	346.49	275.67	273.13	307.98	317.39	444.48	400.79	348.61	369.23
Laclede MO	409.57	455.12	466.54	426.88	356.36	285.47	277.02	310.66	348.41	485.58	436.70	365.49	385.32
Vectren IN	556.70	538.45	476.61	420.53	345.82	268.51	247.98	292.00	317.27	491.09	442.17	360.40	396.46
Dominion OH	413.38	407.75	412.43	334.28	280.20	264.10	317.67	381.14	444.00	531.64	550.94	477.15	401.22
NiSource IN	505.68	543.82	507.62	443.96	374.41	308.65	277.14	312.75	335.30	457.66	413.09	393.59	406.14
ENBRIDGE	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13
PSE&G NJ	465.16	487.13	494.00	481.81	414.22	335.61	294.09	340.34	347.26	495.02	450.89	377.05	415.21
NWN OR	565.95	594.68	572.40	513.51	407.26	271.33	248.77	301.12	297.77	484.07	418.42	317.75	416.09
Questar UT	520.24	540.77	550.04	518.94	405.67	304.29	280.98	303.52	317.67	473.14	439.02	367.78	418.51
Puget WA	530.06	579.79	599.60	530.39	401.37	275.92	252.96	329.16	367.08	599.10	537.62	424.88	452.33
Iberdrola NY	608.01	598.08	628.25	536.61	445.68	357.07	310.00	333.86	357.10	540.96	502.44	467.44	473.79
WGL DC,MD,VA	611.75	640.44	665.81	563.86	450.19	337.66	306.81	343.00	366.36	533.48	482.78	404.79	475.58
ConED NY	587.03	599.79	598.37	526.03	425.24	328.45	318.54	353.06	404.40	615.50	629.20	530.21	492.99
DTE MI	546.02	740.78	696.00	643.17	553.28	399.39	355.18	396.21	478.19	618.18	559.42	468.51	537.86
National Grid MA	741.15	645.31	666.96	636.16	522.27	449.45	388.21	425.85	454.90	678.73	620.88	553.12	565.25
National Grid NY	714.04	716.95	746.27	692.64	536.39	414.05	370.21	405.05	441.03	654.59	609.33	516.89	568.12
Integrys IL	674.36	691.14	735.84	659.73	554.94	512.36	443.86	525.54	546.50	725.11	656.78	529.28	604.62
National Fuel NY	812.87	835.54	829.80	749.91	617.50	542.94	492.86	495.34	508.14	631.94	562.96	496.06	631.32
25 Company Average	502.77	521.26	521.39	468.87	383.90	303.87	283.00	321.32	350.04	497.90	458.79	387.79	416.74
Subgroup Average	482.88	484.13	495.48	453.15	366.07	284.42	259.79	291.42	314.89	460.21	426.41	359.53	389.86
Enbridge	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13

Total Cost (Cdn$) Per Volume (10^3 m^3)													Average
Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2000 - 2011
NiSource IN	40.98	55.36	50.23	45.73	37.32	32.06	30.38	31.98	33.37	49.80	41.57	36.29	40.42
Nicor IL	41.46	47.85	45.62	43.69	38.84	29.23	28.76	33.16	35.98	54.79	52.87	41.48	41.14
PSCO CO	47.55	50.93	51.76	47.15	38.32	25.34	25.69	30.41	32.23	53.93	52.23	43.39	41.58
CenterPoint MN	53.83	61.14	56.46	52.30	43.08	36.79	35.95	38.61	40.76	60.79	55.83	50.62	48.85
Columbia OH	64.82	64.46	54.30	47.48	39.92	37.01	39.16	49.62	54.42	84.75	76.10	56.41	55.70
WE WI	65.15	71.75	71.73	62.29	54.02	39.03	42.32	42.76	49.71	70.89	73.03	60.05	58.56
ENBRIDGE	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53
Ameren IL	70.98	78.98	78.18	66.57	56.66	41.63	48.75	52.76	53.96	78.44	67.43	55.13	62.45
Vectren IN	76.78	84.54	73.10	64.60	56.36	43.91	44.42	49.30	51.20	88.79	74.42	60.29	63.98
Dominion OH	58.28	67.93	65.10	52.38	44.10	41.68	55.02	62.80	71.11	97.01	92.41	76.68	65.37
MGE MO	40.23	119.00	43.44	51.25	64.82	47.19	50.77	58.19	61.05	94.29	87.62	79.28	66.43
Consumers MI	71.36	84.68	87.96	77.16	69.60	58.10	55.87	59.52	63.39	98.27	94.95	77.67	74.88
PSE&G NJ	57.23	76.63	75.35	69.92	80.14	67.92	66.24	69.72	73.17	102.13	95.32	76.61	75.86
NWN OR	86.51	99.01	98.81	93.83	74.63	50.23	46.17	56.19	55.24	100.89	93.34	65.89	76.73
Questar UT	85.85	91.30	96.98	104.87	82.06	65.03	59.09	57.26	56.12	88.26	82.62	69.49	78.24
BG&E MD	81.51	91.05	89.61	76.42	70.37	56.57	64.36	66.74	71.07	101.40	93.36	84.79	78.94
ConED NY	91.85	107.42	90.40	93.10	77.63	58.46	51.82	51.41	58.92	88.52	97.80	79.98	78.94
Iberdrola NY	96.99	106.39	108.77	87.94	76.15	62.55	60.75	60.48	64.61	100.92	98.11	90.67	84.53
Laclede MO	99.89	95.14	113.81	91.97	83.67	69.43	71.25	76.39	82.82	118.88	108.15	91.11	91.88
National Grid NY	99.15	104.81	109.94	109.19	97.00	72.50	67.27	68.39	79.19	117.50	105.80	87.64	93.20
Integrys IL	92.37	108.52	108.36	92.69	84.08	79.35	75.37	84.76	83.49	117.16	112.01	88.74	93.91
WGL DC,MD,VA	108.48	136.75	130.32	114.12	96.57	71.67	73.28	73.62	81.05	116.46	100.53	93.05	99.66
Puget WA	99.23	117.93	124.20	115.76	92.22	64.34	58.83	74.64	81.18	139.15	136.09	96.32	99.99
National Grid MA	125.43	112.17	115.38	111.07	96.81	92.91	77.96	81.23	93.44	145.08	99.40	79.35	102.52
DTE MI	67.97	98.58	147.01	125.18	117.29	97.12	101.04	102.41	120.45	163.29	163.01	128.21	119.30
National Fuel NY	136.83	151.77	147.58	129.53	114.03	102.90	104.97	96.79	102.43	132.22	121.90	104.55	120.46
25 Company Average	78.43	91.36	89.38	81.05	71.43	57.72	57.42	61.16	66.01	98.54	91.04	74.95	76.54
Subgroup Average	75.88	83.91	83.88	79.01	69.54	55.88	53.33	55.45	60.24	90.22	79.43	66.20	71.08
Enbridge	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53

BOARD STAFF RESPONSE TO TCU1.11

In Undertaking TCU1.11 (Transcript 1 page 99) , Concentric Energy Advisors (CEA) was asked to provide the sum of capital costs and OM&A costs for each company in the sample, for the industry as a whole (the 25 US gas distribution companies), and for Enbridge, and to divide this sum by total customers. CEA was asked to perform this calculation for the 2010 and 2011 years.

In its response to TCU 1.11, CEA provided these calculations on average for the 2000-2011 period, rather than for each of the 2010 and 2011 years (the same years CEA highlighted in its benchmarking analysis).

Pacific Economics Group Research (PEG) was able to undertake these computations itself, using the data previously provided by CEA in advance of the Technical Conference. The tables below present the requested data for Enbridge and the 25 US gas distributors for the 2010 and 2011 years, respectively. In both years, companies are ranked in ascending order from one to 26 in terms of total unit costs (i.e. total cost per customer).

It can be seen that Enbridge's total cost per customer was $0.47 in 2010. This ranked Enbridge 15th of the 26 gas distributors in that year. Enbridge's total cost per customer was $0.53 in 2011, which ranks Enbridge 21st of the 26 gas distributors.

Witness: Dr. Lawrence Kaufmann, PEG

2010 Unit Cost Ranking

Rank	Company	Unit Cost
1	Public Service Company of Colorado (CO)	$0.27
2	CenterPoint Energy Resources Corp. (MN)	$0.31
3	Northern Illinois Gas Company (IL)	$0.32
4	Columbia Gas of Ohio, Incorporated (OH)	$0.37
5	Ameren Corporation (CILCO,CIPS,IP)	$0.39
5	Baltimore Gas and Electric Company (MD)	$0.41
7	Wisconsin Energy Corporation (We Energies) (WI)	$0.41
8	Southern Union Company (MO)	$0.42
9	Consumers Energy Company (MI)	$0.42
10	NiSource Inc. (IN)	$0.43
11	Vectren Corporation (IN)	$0.44
12	Questar Gas Company (UT)	$0.44
13	Northwest Natural Gas Company (OR,WA)	$0.45
14	Laclede Gas Company (MO)	$0.46
15	**Enbridge Gas Distribution**	**$0.47**
16	Public Service Electric and Gas Company (NJ)	$0.48
17	Iberdrola, S.A. (NY)	$0.48
18	Washington Gas Light Company (DC,MD,VA,WV)	$0.51
19	Dominion - East Ohio Gas Company (OH)	$0.52
20	Puget Sound Energy, Inc. (WA)	$0.54
21	DTE Energy Company (MI)	$0.58
22	National Fuel Gas Distribution Corporation (NY)	$0.59
23	National Grid (NY)	$0.62
24	National Grid (MA)	$0.63
25	Consolidated Edison, Inc. (NY)	$0.66
26	Integrys Energy Group, Inc. (IL)	$0.69

Witness: Dr. Lawrence Kaufmann, PEG

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2011 Unit Cost Ranking

Rank	Company	Unit Cost
1	Public Service Company of Colorado (CO)	$0.24
2	Northern Illinois Gas Company (IL)	$0.27
3	Columbia Gas of Ohio, Incorporated (OH)	$0.30
4	CenterPoint Energy Resources Corp. (MN)	$0.30
5	Ameren Corporation (CILCO,CIPS,IP)	$0.33
6	Wisconsin Energy Corporation (We Energies) (WI)	$0.37
7	Northwest Natural Gas Company (OR,WA)	$0.37
8	Vectren Corporation (IN)	$0.37
9	Baltimore Gas and Electric Company (MD)	$0.37
10	Southern Union Company (MO)	$0.38
11	Questar Gas Company (UT)	$0.39
12	Consumers Energy Company (MI)	$0.39
13	NiSource Inc. (IN)	$0.40
14	Public Service Electric and Gas Company (NJ)	$0.41
15	Laclede Gas Company (MO)	$0.42
15	Puget Sound Energy, Inc. (WA)	$0.45
17	Washington Gas Light Company (DC,MD,VA,WV)	$0.45
18	Dominion - East Ohio Gas Company (OH)	$0.46
19	Iberdrola, S.A. (NY)	$0.47
20	DTE Energy Company (MI)	$0.51
21	**Enbridge Gas Distribution**	**$0.53**
22	National Fuel Gas Distribution Corporation (NY)	$0.55
23	National Grid (NY)	$0.56
24	Integrys Energy Group, Inc. (IL)	$0.59
25	Consolidated Edison, Inc. (NY)	$0.61
26	National Grid (MA)	$0.61

Witness: Dr. Lawrence Kaufmann, PEG