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Manitoba Hydro
2017/2018 and 2018/2019 General Rate Application

General Service Small / General Service Medium Customer Classes and Keystone Agriculture Producers

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19. Transcript pages 2075-2078

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22. *Principles of Public Utility Rates*, Second Edition, James C. Bonbright

23. *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*, 2015 SCC 45

24. Manitoba Public Utilities Board, Board Order 7/03

25. Decision from Nova Scotia Utility and Review Board, NSUARB-NSPI-P-892

TAB 1

through that perspective, that's the prism that you've
provided your testimony and your evidenced through
today and in this -- these proceedings, correct?

DR. ADONIS YATCHEW: Yes. And that's
based on the idea that come -- firms and individuals
make their decisions on -- over longer-term
expectations than just what's going to happen next
year.

MR. CHRISTIAN MONNIN: And you -- I
had a series of questions for you on the issue of rate
shocks and regulatory signaling but that's been well
canvassed.

But the takeaway from that, at least my
understanding is, assuming that the Board accepts the
proposed rate application in this General Rate
Application, that is, in your evidence that will
telegraph to the public and to the ratepayers that
we're likely falling down the path of -- of all of the
-- the rate increases that are being proposed?

DR. ADONIS YATCHEW: Not with
certainty, but that's -- that would -- that would form
a -- a certain expectation. And again, just referring
to an answer that I gave earlier, it -- once you've
accepted that -- that the primary objective here is a
target -- financial ratio within a certain timeframe,

if that's the rationale for the -- primary rationale for accepting this 7.9 in this application than that rationale one would have to try to appreciate why that rationale changes the following year.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: I'd like to ask you a few questions about the issue of rate smoothing, or smoothing of rates as set out in your -- your report. You had some discussion with that, most recently with My Friend Mr. Cordingley, for the Green Action Centre.

You state in your evidence -- and if you -- if you want to track it, there's no need to go there, but that's at page 43, paragraph 117. You state in your evidence that in the past, electricity rates in Manitoba have increased steadily but relatively smoothly over similar time frames. And -- and -- I am taking that's a comparison to what's being proposed. What you mean by that statement?

DR. ADONIS YATCHEW: I -- I'm sorry, which paragraph are you at?

MR. CHRISTIAN MONNIN: I believe it's

TAB 2

reassurance to capital markets that, in fact, the rate -- the Board at least is not concerned about Manitoba Hydro's self-supporting status.

MR. CHRISTIAN MONNIN: And how -- how would the Board go about doing this, Mr. Colaiacovo?

MR. PELINO COLAIACOVO: I think by enunciating a policy on how rates are going to be managed and -- and reassuring markets that rates will be managed in a fashion to ensure that Manitoba Hydro continues to pay its bills, as it has in the past.

And I think that will be a reassuring message.

MR. CHRISTIAN MONNIN: Thank you. Diana, could you please go to page 11 of 161. Looking at lines 11 down to 15.

Mr. Colaiacovo, I just -- and I'm also going to take you then to slide 35 of -- of your presentation. I'm just trying to get clarification from you.

Here in your report you write:

"It's important to note that despite the change in forward projections based on Manitoba Hydro's target, debt/equity ratio and timing goal, Manitoba Hydro has not

not] requested that PUB formally
endorse or otherwise agree with
either the target level or the
timing goal."

And it goes on. If you can please go to slide 35 please, Diana. And under the first bullet:

"Manitoba Hydro has emphasized its
debt ratio target and timing goal in
its application." [you write] "The
previous timing goal mid-2030s for
achievement of the target has been
explicitly repudiated and the PUB is
being asked to endorse a new
position through its rate decision."

And there seems to be a --

MR. PELINO COLAIACOVO: Yeah, a --

MR. CHRISTIAN MONNIN: A little discrepancy.

MR. PELINO COLAIACOVO: Yeah, perhaps I can clarify. I think in the -- in the -- in the report I was saying that the application is asking for rates for two (2) years specifically. I think the only way that you can come to a conclusion that those rates are required is if you believe that the target of 75 percent debt and the timing goal must be achieved by 2027; if you don't believe that, then the 7.9 percent rate increase, I believe, does not have sufficient support.

Wh -- I've restated it perhaps with a poor choice of words using the word "endorse," but on this slide, what I'm essentially saving -- saying is unless -- well, it's the same point, unless the Board comes to the conclusion that achieving 75 percent by 2027 is, in fact, important in the way that Manitoba Hydro has described it in its application, then you know they -- they will not come to the conclusion that 7.9 percent is the right number.

If, on the other hand, the previous timing goal of mid-2030s for achievement of 7. -- 7.5 percent continues to be supported by the PUB, then you won't get to a 7.9 percent increase, you'll get to some other increase that's not 7.9 percent.

So I apologize if that the -- the - the words appear to be in conflict but the message has been the same.

MR. CHRISTIAN MONNIN: Thank you. Mr. Colaiacovo, previously we had heard evidence from Dr. Adonis Yatchew and he gave testimony, in broad terms, in order to assess likely impacts and responses of various customer groups of rate increases of the proposed magnitudes, as well as the implications for the Manitoba economy as a whole.

And in his concluding observations, I'd just like to see if you're able to comment on this. In his concluding observations, Mr. Yatchew indicated that approval of the increases that are being proposed by Manitoba Hydro, 7.9 percent, will suggest the acceptance of Manitoba Hydro's arguments and its focus on the time profile of future financial ratios.

Is that something that you would agree with?

MR. PELINO COLAIACOVO: Yes, I think he's essentially saying the same thing I am. The only way you can rationally conclude that 7.9 percent is necessary is if you believe 75 percent must be achieved by 2027; other -- if you don't believe that 75 percent debt must be achieved by 2027, then I don't think there is a rational basis for concluding that 7.9 percent increases are necessary.

MR. CHRISTIAN MONNIN: Thank you. And this is a -- I have one (1) or two (2) more questions. I'm almost done, Mr. Chair.

Returning to your report at page 53 of 161, in particular, at lines 10 through 14, you state:

TAB 3

be adjusted.

The main challenge for you is to fix the rate increase for April 1st, 2018. You are not being asked to approve five (5) years of this rate increase. You are not being asked to approve Manitoba Hydro's new financial plan. What my client seeks is a 7.9 percent increase effective April 1st, 2018. The Board can take comfort in the fact it cannot be wrong in awarding 7.9 percent on April 1st.

The evidence demonstrates that Manitoba Hydro is currently not generating sufficient revenue to pay each day what it owes and what is -- it is legally obliged to set aside. We are not relying on forecasts or projections to come to that conclusion. You also don't need to rely on forecast to recognize the immediate financial impact of Bipole III coming into service in the summer of 2018.

Let's begin by looking at the financial impact of Bipole III in the coming year. Bipole III will come into service in August of 2018; that's this test year. It is a reliability project, necessary to ensure Manitobans continue to receive reliable power. Bipole does not, however, generate any revenue to speak of. It's an added cost and it is substantial.

Slide 4. Until -- until now all that

has been included in revenue requirement -- requirement on account of Bipole III is the annual contribution to the Bipole III deferral account. Manitoba Hydro's domestic revenue in 2718 -- 2017/2018 is one thousand four hundred and sixty-four million dollars ($1,464 million) which amount is not currently covering expenses.

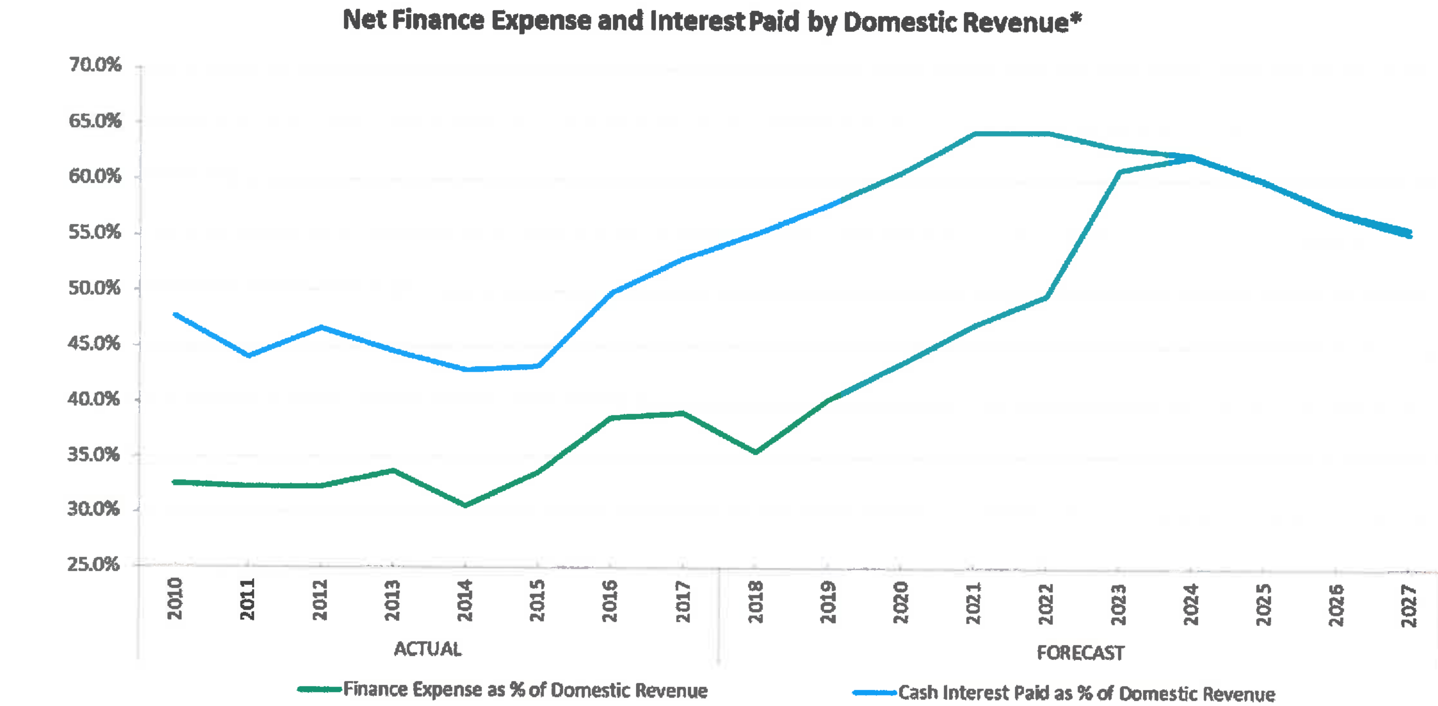
In August of this year, we will add another $332 to Manitoba Hydro's expenses -- 332 million not -- we'd be good with three thirty (330). Absent an increase in rates, Manitoba Hydro cannot pay any of that out of current rates. No rate increase means we will have to borrow.

This Board made the sensible decision not to wait to introduce the entire cost of Bipole III to ratepayers in the month it comes into service. Instead, the Bipole III deferral account was established a number of years ago under Order 43 of '13 and a portion of each rate increase since that time has been designated for the purpose of the Bipole III deferral account. As a result, 11.1 percent of approved rates are being allocated to the Bipole III deferral account. Upon in-service of Bipole III, the amount formerly collected for the deferral account can, at least notionally, be applied to offset Bipole

TAB 4

A 20 Year 3.95% Rate Path Is Too Long

- After Keeyask in 2024 $1.25B in debt cost is supported by $2B in domestic revenue
- 63 cents of every ratepayer dollar goes towards paying debt service costs
- Even a modest 1% increase in interest rates will have a significant impact



*20 Year WATM at MH15 Rates
Interest Paid is presented gross of capitalized interest

Source: Exhibit MH-64 Slide 21

TAB 5

or twenty (20) years to reach a goal, the risk that you may never reach that goal is significantly higher than if you shoot for a ten (10) year goal.

MR. JAMES MCCALLUM: Yeah. And just to pick up on your analogy, Mr. Peters, that what -- what I think Mr. Shepherd is saying is that the stairs are -- are higher, but they're also wider. The other plan has stairs that would take longer and are much narrower. You're walking on a tightrope for a very, very long period of time.

MR. BOB PETERS: Would it be correct, Mr. Shepherd, that Manitoba Hydro hasn't conducted an analysis of the rate impacts on the various customer classes in terms of what their economic impact would be?

MR. KELVIN SHEPHERD: I think it would be fair to say that I haven't seen an analytical impact study. We've certainly considered qualitatively, and discuss the risk, but I would tell you, personally, I have not seen any kind of quantitative analysis or attempt to quantitatively identify those impacts beyond, I would say, certainly some views on understanding what the, you know, impacts might be in terms of, you know, low income customers and bill affordability, and those types of analysis, which I -- I would say we have seen.

MR. BOB PETERS: Yeah. And -- and I wasn't suggesting that you don't run bill impact schedules and -- and the like. Your -- your materials have those. But I was thinking more as to whether Manitoba Hydro prepared an economic impact study on Manitoba -- or the Province of Manitoba, or on Manitobans for the proposed rate increases in Manitoba Hydro's new ten (10) year plan, and I'm hearing that that hasn't expressly been done.

MR. KELVIN SHEPHERD: No. I could ask Jamie to confirm this, since he's more familiar with all the details that went into the application, but to my understanding, we didn't complete an overall attempt to quantify the economic impact on Manitoba.

MR. JAMES MCCALLUM: I -- yeah. No, I don't -- I don't have anything to add, that there was an overt study. There was obviously extensive discussion inclusive of with our Board of Directors around different rate strategies in different time frames by which to address our issues and the economic impacts thereof.

MR. BOB PETERS: I wanted to turn back, Mr. Chair, panel members, just to continue on with the -- the equity trajectory and the rate

TAB 6

MR. CHRISTIAN MONNIN: My McCallum, Mr. Shepherd, I'm over here. If you just lean back you can completely ignore me and you won't see me.

My name is Christian Monnin. I'm counsel for the Intervenors General Service Small and General Service Medium customer classes, in addition to Keystone Agriculture Producers.

You'll be pleased to know that my intended cross-examination for you gentlemen this afternoon is relatively short in comparison to what you've gone through to date.

I'd like to ask you a few questions with respect to the issue of reduced load growth. My understanding is that one (1) of the main drivers for this request for rate increases, the capital plan, but another one is -- is the -- is the anticipated or expected reduced domestic load growth; is that correct?

MR. KELVIN SHEPHERD: Yes, that's one of the factors.

MR. CHRISTIAN MONNIN: Is it fair to say that Manitoba Hydro recognizes that for every percentage increase in real electricity prices there's a corresponding result in a decrease in domestic consumption; is that fair to say?

MR. KELVIN SHEPHERD: There's definitely a sensitivity to it, yes. And, I mean, I could ask Mr. McCallum to comment more, but we've attempted to quantify that in the -- in the forecast.

MR. CHRISTIAN MONNIN: And in that regard, Manitoba Hydro has then acknowledged that with a rate increase there will be a corresponding reduction in the consumption on the domes -- domestic load growth?

MR. KELVIN SHEPHERD: Yes, there's -- there is some linkage between pricing and -- and consumption. There's no doubt about that.

MR. CHRISTIAN MONNIN: And with respect to the proposed rate increase that the Corporation is seeking, what -- what extent of the 7.9 percent is to offset the anticipated reduction domestic load growth that will occur from these rate increases?

MR. JAMES MCCALLUM: I don't have an answer to that. I don't recall having done that analysis, but tomorrow we'll have Ms. Morrison here with us who -- who is the expert in the load forecast.

MR. CHRISTIAN MONNIN: Okay, but I take it from your answer you haven't done that analysis, but has -- has Manitoba Hydro done that analysis?

MR. JAMES MCCALLUM: Subject to check, not that I'm aware of.

MR. CHRISTIAN MONNIN: Thank you. I'd like to ask you some questions on intergen -- intergenerational fairness.

In particular, Mr. McCallum, I believe your evidence yesterday, and we don't need to go there, at page 260, lines 10 through 18, the end of that paragraph you indicated that if anyone has been treated unfairly it's not been today's ratepayer.

Is that fair to say that's part of the evidence you gave yesterday?

MR. JAMES MCCALLUM: Those were an excerpt of my comments, yes.

MR. CHRISTIAN MONNIN: And is it fair to say that that -- that evidence is anchored in the logic or that statement is anchored, among other things, but primarily in the concept of fairness between generations with respect to the assets that the Company holds?

MR. JAMES MCCALLUM: I think it would be anchored in the comment that from my point of view or the perspective that from my point of view, today's ratepayers are not paying the full and current cost of

TAB 7

Utility more than it had requested.

MR. CHRISTIAN MONNIN: But, sir, you're not going to disagree that it gave a lesser increase, and then conditional increases where Manitoba Hydro was required to return before the Board to justify that these conditional increases were necessary.

Do you agree with that, sir?

MR. GREG BARNLUND: No, I think to make clear, the Utilities Board awarded Manitoba Hydro a larger increase for August 1 than it had initially requested, and then followed by requiring Manitoba Hydro to file, on a provisional basis, updated financial information prior to considering any -- or its next rate increase for April 1 of 2005.

MR. CHRISTIAN MONNIN: Is it safe to say, sir, that Manitoba Hydro views the issues of economic competitiveness and economic development as something that, while important, are mostly beyond its mandate and control?

MR. JAMES MCCALLUM: Sorry, Mr. Monnin, can you repeat the question?

MR. CHRISTIAN MONNIN: Is it safe to say that Manitoba Hydro views that the issues of economic competitiveness and economic development is something that, while important, are mostly beyond Manitoba Hydro's mandate or control?

MR. JAMES MCCALLUM: Well, I think clearly Manitoba Hydro has an interest in economic development. Economic development and -- and growth support Manitoba Hydro's business. I think our concern would be trying to use rate strategy in order to artificially deal with issues of economic competitiveness that go far beyond electricity rates.

MR. CHRISTIAN MONNIN: Is it safe to say that in preparing this application Manitoba Hydro did not turn its mind to the impact of the impending carbon tax and what that will have on -- on ratepayers' ability to absorb the proposed rate increases?

MR. JAMES MCCALLUM: Well, at the time we prepared our application we didn't have knowledge of the Province of Manitoba's choices around the carbon tax.

MR. CHRISTIAN MONNIN: You had knowledge that the federal government was imposing --

MR. JAMES MCCALLUM: Of course.

MR. CHRISTIAN MONNIN: -- which would apply to all provinces, unless a province has opted out and did their own; correct?

MR. JAMES MCCALLUM: That's my understanding.

MR. CHRISTIAN MONNIN: So there was a knowledge of a carbon tax of one (1) form, shape, or another at the time; correct?

MR. JAMES MCCALLUM: I would say that's correct.

MR. CHRISTIAN MONNIN: So is it safe to say that that didn't factor into Manitoba Hydro's analyses while preparing this application?

MR. JAMES MCCALLUM: I wouldn't -- yeah, I would agree with that directionally.

MR. CHRISTIAN MONNIN: And is it safe to say that in the same vein that Hydro has not attempted to identify the trade-offs between the impact of the rate increases on its financial health -- health on the one (1) hand, and that of the province and the ratepayers on the other hand in preparing its application.

Is that safe to say?

MR. JAMES MCCALLUM: Sorry, can you repeat your question?

MR. CHRISTIAN MONNIN: Sure. In the same vein, is it fair to say that Manitoba Hydro has not attempted to identify the trade-offs between the impact of the rate increases on its financial health, on the one (1) hand, that of the province and the ratepayers on the other hand?

MR. JAMES MCCALLUM: Oh, I don't think I'd agree with that. I think we had a tremendous amount of discussion around the executive and board around impacts of the rate increases on -- on the economy. I think, ultimately, our job is to look after the health of the Utility and I think what we put forward here we've said is what we believe is the minimum required to do so.

MR. CHRISTIAN MONNIN: And in those deliberations was an in-depth analysis done on behalf of Manitoba Hydro on the impacts that these rate increases would have on the one (1) hand, and on the benefits -- or on the impacts to the province and the ratepayers on the other hand?

MR. JAMES MCCALLUM: In-depth analysis -- no, when we relied on the judgement and experience of the executive team and its Board of Directors who are collectively a group of fairly experienced individuals.

MR. CHRISTIAN MONNIN: Mr. McCallum, members of the panel, members of the Board. Thank you. Those are my questions.

TAB 8

MR. CHRISTIAN MONNIN: And you would agree that members of the -- of the -- the MIPUG panel, you would agree with me that in -- in the evidence that's been filed, MIPUG has stated on several occasions that, for example, at Mr. Bowman -- and I apologize for making everyone bounce around -- Mr. Bowman's prefiled testimony, page 4-10 lines 25 through 29, the first full sentence:

> "The Hydro filing provides no apparent estimate of the econom -- economic impact on Manitoba of raising rates outside the lim -- limited concept of inc -- incremental elasticity, how much less power might be used on an incremental basis due to higher rate increases due to customers' price response."

And again, at -- at page 4-11, lines 6 through 8, along with potential industrial impacts related to risk of shutdown, on job loss, there's no information as is provided by Hydro regarding the basic broader economic -- broader economy -- economy impacts of the higher revenues being charged by Hydro solely for the purpose of Hydro's own debt reduction.

And -- and once again, at page 4-13, I said I wouldn't belabour the point, but clearly I am by underscoring again at lines 23 to 24, again, a comment about the limited information regarding the potential adverse economic impact.

And -- and so my -- my question is -- is going: Would you agree with me that based on these comments, and -- and the underscoring of the fact that there is limited information, the economic impacts -- so based on this, would -- would you agree with me that it would be of benefit to these proceedings, and of particular benefit to this Board if it could review a properly conducted macroeconomic analysis which addresses the full impacts of the projected rate increases?

MR. PATRICK BOWMAN: Well, Mr. Monnin, I -- I think my best answer is I -- I hope not. And -- and I say that because I have never had to go through this type of process to assess an applicant's application before, because I've never opened an application that says we're going to raise rates to a significantly different degree than has ever been done in relation to inflation, and it's for the benefit of the government and the benefit of ratepayers, and -- but then not say another word about how it's going to affect the -- the economy, which would be, I would think, supporting points about that basic case.

I would rather not have to assess that basic case. It seems to me that there is plenty of room to deal with the cost pressures in the IFF in a normal, regulatory context, the way I would in any jurisdiction, and -- and in those jurisdictions, I wouldn't -- I wouldn't begin, you know, how many jobs are going to be lost.

But if someone says the credit-rating agencies, we rely on the government's credit rating, and we need to help fix it. And in fact, the government's credit rating is based on things like GDP, but they don't make a comment about how them fixing it are going to affect the GDP. It -- there's -- there's a link missing. I -- I -- you have no idea how much I would prefer not to have to get into assessing the -- the assertions made in terms of -- of completing that link. But I think it's a -- it's a significant -- it's a significant hole in -- in the material provided.

MR. CHRISTIAN MONNIN: So when we say -- say that, to summarize that answer is that you hope not, but it -- it -- there's -- there's the possibility of a benefit for -- for proceeding with such a macroeconomic analysis?

MR. PATRICK BOWMAN: I -- I'm suggesting that if you're going to impose rate changes that are -- that are many multiples of anything that people have experienced here before, and your assertion is that those -- that is being done for the -- for -- to achieve certain benefits, I think you're -- the obligations on you to support that those benefits would arise and that they wouldn't be undermined by your very actions.

MR. CHRISTIAN MONNIN: Mr. Forrest, you're -- you're looking at me. Did you want to -- to add to that?

Mr. Chair, this -- I have one (1) last question, and -- and I do proceed with some trepidation, knowing what My Friend, Mr. Ghikas's previous objections, and -- and I will put that question forward is Mr. Bowman, why are you so popular? You don't need to answer that. Thank you.

THE CHAIRPERSON: Thank you, Mr. Monnin. You know, I've never had that question asked of me. We'll adjourn for fifteen (15) minutes. Thank you.

--- Upon recessing at 2:40 p.m.

TAB 9

Now, I had a series of questions for you on oil and natural gas markets. Those have also been substantially covered, but I just want to touch upon one (1) particular point, and that's that fuel switching.

You -- you seem to put a lot of emphasis on these -- these rates would possibly lead some ratepayers, some of my clients, for example, in -- in agriculture, or manufacturing to -- to go to different fuels, natural gas, in particular. Is it safe to say that for your report, you didn't really get very granular and to the ability of the agricultural sector to -- to switch to -- to fuel?

DR. ADONIS YATCHEW: No, I -- I did not.

MR. CHRISTIAN MONNIN: Natural gas, rather.

DR. ADONIS YATCHEW: And that's certainly an analysis that can be done, but it was not done in the context of this report.

I -- there's a fair amount of territory that I was trying to cover here, and there was all kinds of detailed analyses that could be done, that are useful to do, that are not in this report.

MR. CHRISTIAN MONNIN: And -- and I

appreciate that. And -- and you'll probably appreciate, having done this -- this exercise before, that most of the folks in my racket, that is, in the law profession, when we do cross-examinations, we tend to ask questions where we hope we know the answer to already, and that's why I put that one to you, sir.

And -- so the same question would be, you didn't do that exercise for the ability of the -- the hotel industry for fuel switching, correct?

DR. ADONIS YATCHEW: That's correct.

MR. CHRISTIAN MONNIN: And the same for manufacturing, you didn't do that same exercise, correct?

DR. ADONIS YATCHEW: That's correct. I -- I -- the information that I was trying to bring forth is these -- the -- the massive empirical evidence that exists out there for response to prices -- electricity prices, and what I didn't really mention here, and did not talk about in the report, but is relevant, it's what's the cross price elasticity? How does the demand for electricity change with changes in the price of natural gas and vice versa? That's another useful to know.

But my analysis was -- was to bring -- relied on those kinds of empirical studies, which, as

I've said earlier, I think can inform the discussion here. However, the distributional effects on a -- the -- the best information that I can -- that I was able to provide relatively easily was the electricity shares of costs on a -- on an industry basis, and that's in Appendix 4.

MR. CHRISTIAN MONNIN: And -- and we'll get to Appendix 4 a little later on in my questions, but I appreciate the answer. Thank you.

I'd like to ask you a -- a few questions about the issue of emerging technologies, which you touched upon in your report.

DR. ADONIS YATCHEW: Yes.

MR. CHRISTIAN MONNIN: And again, I'd -- I'd -- there's no need to go there, but if -- if you do want a reference, starting at page 12, you made mention to the fact that the cost of emerging technologies which are transforming electricity have been dropping at a rapid pace. And the point here, Dr. Yatchew, is these alternatives or emerging technologies, would you agree with me they may erode the demand for Manitoba Hydro's electricity?

DR. ADONIS YATCHEW: They may, yes, both domestic demand and -- and its export demand or prices, the prices that it can -- that it can obtain

TAB 10

consuming firms to other North American jurisdictions."

Now, you touched upon that with -- with My Friend Mr. Cordingley from the Green Action Centre. Now, I'm going to try to string this together. If you take that point of your scope work and then go to page 50 of your report --

DR. ADONIS YATCHEW: M-hm.

MR. CHRISTIAN MONNIN: -- where you have electricity share -- a table of electricity shares by major GDP sector. Would you agree with me that you state here that manufacturing is the most electricity-intensitive (sic) sector, here, at 1.23 percent?

DR. ADONIS YATCHEW: It's very close to agriculture.

MR. CHRISTIAN MONNIN: And I appreciate that. But sticking with the manufacturing being the highest, and I believe at page 72, again, no need to take you there, but would you agree that your evidence was that basic chemicals, as a manufacturer, was identified -- along with pulp and paper -- but as a manufacturer, basic chemicals was identified as the most vulnerable of the industries?

DR. ADONIS YATCHEW: It has the

highest electricity share of total costs --

MR. CHRISTIAN MONNIN: And we -- we'd find that at your Appendix 4, correct?

DR. ADONIS YATCHEW: That's correct, 18.1 percent in Appendix 4.

MR. CHRISTIAN MONNIN: And pulp and paper would be 6.98 percent, but sticking with -- with the -- the basic chemicals --

DR. ADONIS YATCHEW: M-hm.

MR. CHRISTIAN MONNIN: -- and at page 60, lines 21, 24, you note that the exchange rates in commodity prices would affect these vulnerable industries, correct?

DR. ADONIS YATCHEW: Yes.

MR. CHRISTIAN MONNIN: And keeping in mind your scope of work and keeping in mind what we've just gone through, would you consider basic chemicals to be at risk of moving to another North American jurisdiction?

DR. ADONIS YATCHEW: I would have to take a look more carefully at what are the other reasons for being located here. You gave agriculture, for example. You're not to move agricultural and agricultural industry. The -- you might not be as competitive.

So I don't know without actually -- I wouldn't know without actually looking at what the options are on a very specific -- in fact, probably company basis rather than just industry basis. It certainly would seem to me that -- that there is -- there would be risk, there.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Dr. Yatchew, thank you very much. Those are my questions --

DR. ADONIS YATCHEW: Thank you, sir.

MR. CHRISTIAN MONNIN: -- Mr. Chair.

THE CHAIRPERSON: Thank you. We'll -- we'll take the afternoon break for fifteen (15) minutes right now. Thank you.

--- Upon recessing at 2:34 p.m.

--- Upon resuming at 2:54 p.m.

THE CHAIRPERSON: Okay, if we could resume. Dr. Yatchew, you met Dr. Williams before, now you're going to meet Mr. Williams. And the reason Dr. Williams -- Dr. Williams here is because we have a second Williams and Mr. Williams will now be asking

TAB 11

MR. CHRISTIAN MONNIN: Page 7 of 32.

DR. JANICE COMPTON: Seven and... sorry.

MR. CHRISTIAN MONNIN: A direct effect.

DR. JANICE COMPTON: Oh, yes, sorry. Yes, that's correct.

MR. CHRISTIAN MONNIN: Okay. And -- but, however, you also state, and I'm paraphrasing here, but you also state that how industries will respond to an increase in rates will vary from entity to entity; is that correct?

DR. JANICE COMPTON: That's right.

MR. CHRISTIAN MONNIN: However, for the report, you make the simplifying assumption that the direct impact is that industries will initially respond to higher Hydro prices or higher rates by reducing spending on other inputs.

DR. JANICE COMPTON: Yes.

MR. CHRISTIAN MONNIN: Which would also have the corresponding affect, I'm suggesting to you, of reducing profits; is that fair?

DR. JANICE COMPTON: It may or may not, that doesn't come out of the model.

MR. CHRISTIAN MONNIN: Okay, but in

addition to these -- the simplifying assumption, your report also recognizes the possibility that businesses may also pass on the cost to consumers in the form of higher prices; correct?

DR. JANICE COMPTON: Yes.

MR. CHRISTIAN MONNIN: And would you agree with me that that is -- apart from the decision of using the simplifying assumption, that passing on the cost to consumers in the form of higher prices is the more likely result of what's going to occur with increasing rates?

DR. JANICE COMPTON: I think I'd need more information to know whether or not it would be more likely or not. The reason why we made this simplifying assumption is because passing on the rates to consumers involves changing the relative prices and the model doesn't allow us to do that.

So we were trying to be as conservative as possible in making our estimates. So the -- the simple way to do that is to think that the -- the firms will re -- revise their production process, revise how they produce their goods and services in a -- to adjust for the higher Hydro prices but that their output levels would be the same, that their prices would be the same. So, in a way, it's -- it's really a very conservative look at how businesses would respond.

MR. CHRISTIAN MONNIN: And do I understand from -- the takeaway from that answer is that because the model was limited, you chose a simplifying assumption?

DR. JANICE COMPTON: Yes.

MR. CHRISTIAN MONNIN: Now, would you be able to comment on this? If -- if you were to move from the simplifying assumption and take into consideration the others -- the other possibility that they would pass on the cost to consumers in the form of higher rate prices, would that have an -- an impact on the economy in Manitoba as a whole?

DR. JANICE COMPTON: It would be hard to say. You'd have to -- so that would mean that the -- the demand from the firms in terms of what they were demanding, we could imagine that they would stay the same but then the prices would be passed on to the consumer so then it would be reduced -- further reducing industry household demand. So then we would leave industry as is and further reduce household demand, you'd have to run that through. It would depend on the different mix of goods and services that are being consumed by households relative to the industries and how intense -- energy intensive those are.

So without running through, it would be very difficult to say whether or not it would have a larger or smaller effect on the economy.

MR. CHRISTIAN MONNIN: Okay. And -- and you also refer to certain industries altering their production in your report.

Is it -- it's at -- would you agree with me that it's safe to say that some industries are not nimble enough to alter their production or are just not able to do so?

DR. JANICE COMPTON: Absolutely. And some -- some would be able to do it very easily to conserve and some -- and change their -- the way that they produce. Some wouldn't be able to do it at all if they have very -- very set production and vary specific ways of producing. But because we're looking at the Manitoba industry on average or -- or, you know, the four hundred (400) -- sorry, four hundred (400) goods and services, the two hundred and sixty (260) odd industries, we just took it as some will be higher, some will be lower.

MR. CHRISTIAN MONNIN: And you didn't in your report -- and hopefully I'm stating the obvious that that you didn't get as granular as that in your report to go down to look at altering production for certain industries; correct?

DR. JANICE COMPTON: No, we don't have that information. You'd have to know more about the production process at each industry level. We know their -- their output and their inputs but in terms of the substitutability between them, that not -- that information is not -- that would be firm information that we don't have.

MR. CHRISTIAN MONNIN: And you also sta -- staying on the point, that you state though:

"Firms may respond by increasing prices. Firms are less likely to pass on the increased costs when they face a competitive market with imports from jurisdictions not subject to the higher price impact."

How did you come to that assumption, or what -- what is that based on?

DR. JANICE COMPTON: Well, that's -- so in the basic economic models of industry, the firms that are looking at it -- that are competing with imports that don't face the same hydro rate increases, they have to -- they still have to compete with their

TAB 12

The new methodology arising out of Order 164/16 puts RCC results, as well as allocated cost by class and cost components, at considerable variance from those derived using the previous methodology used in PCOSS14-Amended as can be seen in the tables below.

Figure 8.12 Comparison of Class RCC Results

Customer Class	PCOSS14-Amended RCC	PCOSS14 164/16 RCC	PCOSS18 RCC
Residential	99.9%	95.5%	94.8%
General Service - Small Non Demand	108.0%	108.5%	112.5%
General Service - Small Demand	104.5%	103.4%	101.0%
General Service - Medium	99.3%	100.3%	98.3%
General Service - Large 0 - 30kV	91.1%	96.1%	99.1%
General Service - Large 30-100kV	99.8%	108.0%	109.3%
General Service - Large >100kV	98.5%	107.1%	108.6%
Area & Roadway Lighting	100.3%	99.5%	100.3%

Figure 8.13 provides the unit costs flowing from PCOSS18 relative to the unit costs flowing from PCOSS14 and Manitoba Hydro's rates.

TAB 13

Table 7-1: PCOSS18 Functionalized Cost to Revenue Comparison ($Millions and cents/kW.h) – All Rate Classes[210]

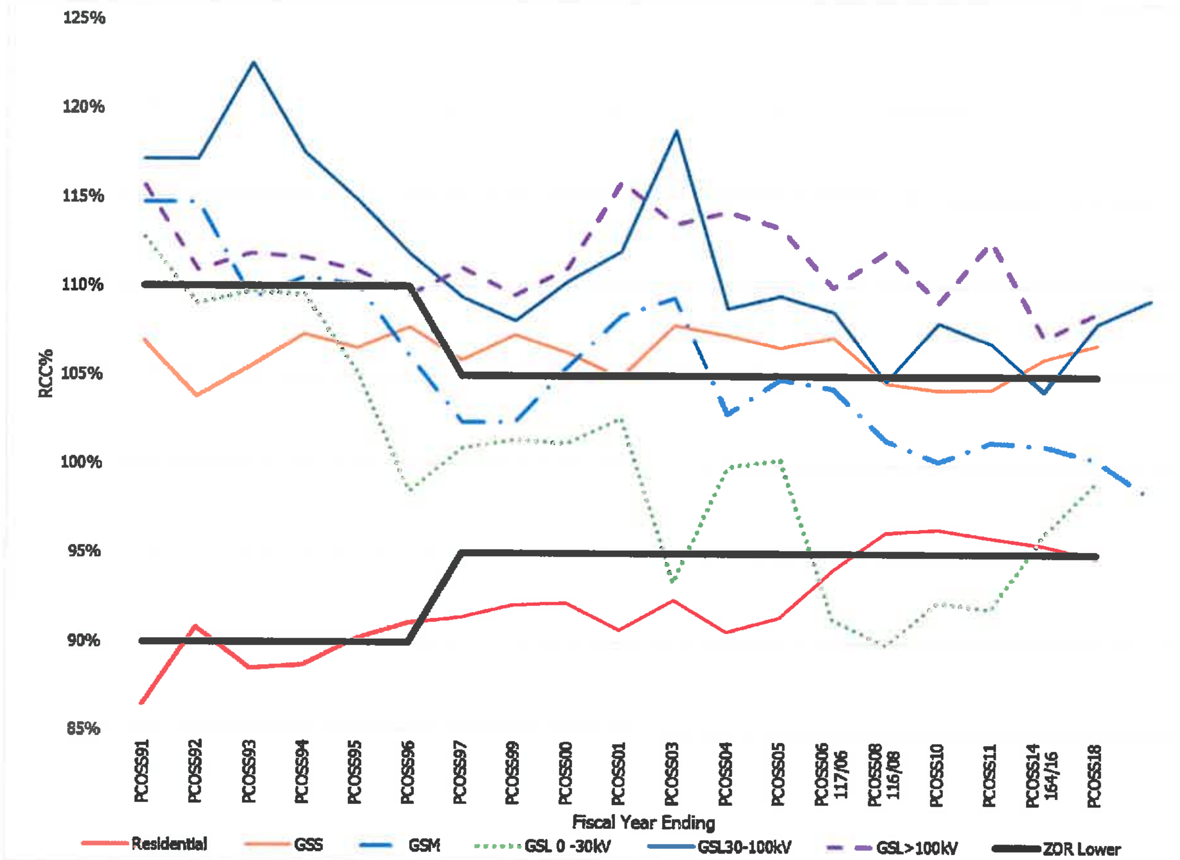
	Residential		GSS-ND		GSS-D		GSM		GSL<30kV		GSL 30-100kV		GSL>100kV	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs														
1 Generation Costs	$422.92	5.57	$83.60	5.15	$107.75	5.02	$155.89	4.86	$81.30	4.66	$69.53	4.40	$194.55	4.32
2 Transmission Costs	$96.88	1.28	$16.92	1.04	$20.98	0.98	$28.62	0.89	$13.77	0.79	$10.90	0.69	$30.31	0.67
3 Export Share	($161.91)	-2.13	($31.31)	-1.93	($40.10)	-1.87	($57.47)	-1.79	($29.61)	-1.70	($25.05)	-1.59	($70.04)	-1.55
4 Bulk Power Costs	$357.89	$4.72	$69.22	$4.27	$88.64	$4.13	$127.04	$3.96	$65.46	$3.75	$55.38	$3.51	$154.82	$3.44
5 plus: Subtransmission-related	$37.24	0.49	$6.46	0.40	$7.98	0.37	$10.84	0.34	$5.18	0.30	$4.08	0.26	$0.00	0.00
6 Distribution	$180.23	2.38	$32.17	1.98	$40.68	1.90	$49.82	1.55	$17.23	0.99	$0.28	0.02	$0.24	0.01
7 Cust. Serv.	$73.65	0.97	$12.66	0.78	$7.80	0.36	$8.30	0.26	$2.92	0.17	$2.18	0.14	$5.59	0.12
8 plus: Distrib. and Cust. Serv.	$253.88	3.35	$44.83	2.76	$48.48	2.26	$58.12	1.81	$20.15	1.15	$2.46	0.16	$5.83	0.13
9 Total Assigned Costs	$649.00	8.56	$120.50	7.43	$145.10	6.76	$195.99	6.12	$90.79	5.20	$61.92	3.92	$160.65	3.57
Rates														
10 Total PCOSS Sales Revenue	$607.11	8.00	$139.48	8.60	$146.98	6.85	$191.74	5.98	$89.65	5.14	$70.00	4.43	$180.46	4.01
Surplus/Shortfall														
11 Rates compared to costs (109)	($41.90)	-0.55	$18.98	1.17	$1.88	0.09	($4.26)	-0.13	($1.14)	-0.07	$8.07	0.51	$19.81	0.44
12 Revenue-to-Cost Ratio (line 10/line 9)	93.5%		115.7%		101.3%		97.8%		98.7%		113.0%		112.3%	
13 Total Class Metered Energy (GW.h)	7,586		1,623		2,146		3,204		1,745		1,579		4,505	

	Lighting		SEP		Domestic Total		Diesel		Exports		Total System	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs												
1 Generation Costs	$4.03	4.90	$0.58	2.27	$1,120.16	4.98	$8.60	59.12	$38.16	0.42	$1,166.92	3.68
2 Transmission Costs	$0.72	0.88	$0.09	0.35	$219.20	0.97	$0.00	0.00	$0.00	0.00	$219.20	0.69
3 Export Share	($1.48)	-1.80	$0.00	0.00	($416.99)	-1.85	$0.00	0.00	$416.99	4.55	$0.00	0.00
4 Bulk Power Costs	$3.28	$3.98	$0.67	$2.63	$922.38	$4.10	$8.60	$59.12	$455.15	$4.97	$1,386.12	$4.38
5 plus: Subtransmission-related	$0.27	0.33	$0.00	0.00	$72.06	0.32	$0.00	0.00	$0.00	0.00	$72.06	0.23
6 Distribution	$17.04	20.68	$0.02	0.09	$337.72	1.50	$0.40	2.72	$0.00	0.00	$338.11	1.07
7 Cust. Serv.	$0.91	1.11	$0.04	0.17	$114.05	0.51	$0.00	0.00	$0.00	0.00	$114.05	0.36
8 plus: Distrib. and Cust. Serv.	$17.95	21.78	$0.07	0.26	$451.78	2.01	$0.40	2.72	$0.00	0.00	$452.16	1.43
9 Total Assigned Costs	$21.50	26.09	$0.74	2.89	$1,446.20	6.43	$9.00	61.84	$455.15	4.97	$1,910.34	6.03
Rates												
10 Total PCOSS Sales Revenue	$21.57	26.17	$0.84	3.31	$1,447.83	6.44	$7.37	50.66	455.15	4.97	1,910.34	6.03
Surplus/Shortfall												
11 Rates compared to costs (109)	$0.07	0.08	$0.11	0.42	$1.63	0.01	($1.63)	-11.19	0.00	0.00	0.00	0.00
12 Revenue-to-Cost Ratio (line 10/line 9)	100.3%		114.4%		100.1%		81.9%		100.0%		100.0%	
13 Total Class Metered Energy (GW.h)	82		26		22,496		15		9,166		31,677	

[210] Functionalized Cost breakdown by rate class per Hydro's 'Rudimentary Model of PCOSS18' tabs 'C Tables Proces', 'D Tables Proces', 'E Tables Proces' and 'Direct Costs', Sales Revenue and Net Export Revenue Allocation from tab 'RCC Summary', Total Class Metered Sales from tab 'Cust, Demand and Energy Summary'. Affordable Energy Fund included as direct-assigned export generation costs ($0.5 million) with variable O&M ($3.5 million) and water rentals ($34.2 million) as provided in Tab 8, page 19 of 34.

TAB 14

Figure 7-2: Revenue Cost Coverage Ratios by Customer Class[233]



Note that the results in Figure 7-2 are as reported in the respective PCOSS – as noted above this has a dampening effect on the true percentage by which each class faces rates over or under measured costs, due to the arithmetic Hydro applies to export revenues.

In this current GRA, Hydro suggests that a new widening of the zone of reasonableness to 90%-110% may be reasonable in light of historical precedence and continuity, ratemaking and policy objectives, the degree of variability in cost allocation methodologies and cost definition and the changing cost structure in future rate applications due to the significant infrastructure investment underway for Manitoba Hydro[234]. Such a revision would not be advisable. The basic premise for utility ratemaking is to recover rates that reflect costs – overall rates to reflect the costs of the utility, and between the classes, rates that reflect the costs to serve that class. Some jurisdictions, such as Newfoundland and Labrador, strictly target 100.00% for

[233] 1991-1994 and 1996 RCC ratios from MIPUG/MH/CR-2(b), Manitoba Hydro 1996/97 GRA. RCC ratios for 1995, 1997, 1999, 2001-2004 and 2006-2018 from Appendix 8.1, page 38, Manitoba Hydro 2017/18 & 2018/19 GRA. 2000 RCC ratios from MIPUG/MH I-30(a), Manitoba Hydro 2015/16 GRA. 2005 RCC ratios from MIPUG/MH I-21(f), Manitoba Hydro 2004 GRA.
[234] PUB/MH I-137a

TAB 15

REVENUE VS. MARGINAL COST UPDATE

Schedule 23 - Updated

MARGINAL COSTS VS. AVERAGE REVENUE COMPARISON

	Marginal Cost (cents/kWh @ 100% Load Factor)				Class Load	Marginal Cost - Trans. & Distr @ Class Load Factor (cents/kWh)				Avg. Rev.	Revenue/ Marginal		
	Gen.	Trans.	Distr.	Total	Factor	Gen.	Trans.	Distr.	Total	(cents/kWh)	Cost		
Residential	4.39	0.57	0.78	5.74	51%	4.39	1.11	1.52	7.03	8.82	125.5%	8.071565	1.092725
General Service -SND	4.39	0.57	0.78	5.74	62%	4.39	0.91	1.25	6.55	9.3	141.9%	7.212336	1.289457
General Service-SD	4.39	0.57	0.78	5.74	67%	4.39	0.85	1.17	6.41	7.66	119.4%	6.960959	1.100423
General Service-M	4.39	0.57	0.78	5.74	73%	4.39	0.78	1.07	6.24	6.83	109.5%	6.640135	1.028594
GSL 0-30	4.39	0.57	0.78	5.74	83%	4.39	0.69	0.94	6.03	5.77	95.8%	6.256749	0.922204
GSL 30-100	4.23	0.55	0	4.78	92%	4.23	0.60	0.00	4.83	4.93	102.2%	4.912036	1.003657
GSL>100	4.23	0.55	0	4.78	94%	4.23	0.58	0.00	4.81	4.46	92.7%	4.878352	0.914243

Sources: GAC/MH 11-24 b) -Updated and PUB/MH I-57 (R)
Appendix 8.1, Schedule 5.3 - for usage data to calculated class load factors
PUB/MH 135 - for Average Revenue values

Note: Revised Marginal Trans. And Distr. Marginal based on class load factor calculated by dividing values based on 100% by the class load factor

ADDITIONAL CONSIDERATIONS

- NO LOAD FACTOR ADJUSTMENT FOR GENERATION CAPACITY COSTS
- NO DIFFERENTIATION OF ENERGY COSTS BY TIME OF USE
- NO ALLOWANCE FOR ENVIRONMENTAL COSTS

TAB 16

Manitoba Hydro

Revenue to Cost Coverage Ratios

Customer Class	PCOSS18 (as filed)	Estimated Revenue Cost Coverage in 2020 with BPIII In Service	
Residential	94.8%	96.7%	Increase
GSS Non Demand	112.5%	115.3%	Increase
GSS Demand	101.0%	101.3%	Neutral
GSM	98.3%	97.4%	Decrease
GSL 0-30 kV	99.1%	96.5%	Decrease
GSL 30-100 kV	109.3%	103.5%	Decrease
GSL >100 kV	108.6%	101.5%	Decrease
A&RL	100.3%	118.2%	Increase

TAB 17

time. Each time you use that card, you accumulate more debt and even more of your income gets eaten up by interest expense. It's a vicious cycle. And if you told -- don't take steps to deal with the debt, the payments become so large that all of your income goes to service that debt, and you have to borrow on another account just to make that credit card's minimum monthly payment.

To stop the cycle, you have to get the debt under control. You need to reduce your expenses. You need to increase your cash flow. You might make changes to your lifestyle, you might cut costs. You might look for ways to increase your income, and we are doing all those things at Manitoba Hydro. Manitoba Hydro's already taken steps this year to reduce its workforce by nearly 15 percent. This includes a reduction in the number of vice-presidents by 30 percent and over the next short while, the elimination of eight hundred (800) full-time positions.

We would not presume to come to this Board with this rate ask without having taken these steps. Unfortunately, these and other cost control measures are not enough to provide Manitoba Hydro sufficient revenue to meet its obligations and manage its risks. We're not going to be able to grow our way out of this predicament. Our domestic load forecast is down, as is our export revenue forecast. We have no choice but to look to the only other tool we have in our toolbox and that is rate increases.

It's fair to ask: How exactly is debt affecting Manitoba Hydro? We're going to be dealing with this in detail but I'll give you a taste. The evidence demonstrates that presently for every dollar Manitoba Hydro collects from Manitoba ratepayers $0.40 goes to service the debt. I can tell you that $0.40 is going up and it's going up soon. It does not include the interest associated with our major capital projects, that means, the interest we're paying today on Bipole III capital spending is not in the $0.40. When Bipole III comes in around nine (9) months from now, it adds $205 million, 205 million, to Manitoba Hydro's interest expense annually; that's a real expense, and it has to be paid with real dollars. Change the slide. Thank you.

By 2024 all the major projects will be complete. How do we look then? That is going to depend on the rate decision you make now. If we don't take corrective action and we continue with the old financial plan with its 3.95 percent rate trajectory,

TAB 18

by 2024 $0.63 of every dollar collected from Manitoba ratepayers will be needed to service Manitoba Hydro's debt.

However, there is an opportunity to change that by following the plan laid out in this application, that amount drops dramatically from -- to $0.45 of every do -- excuse me, $0.45 of every dollar. From $0.63 to $0.45, that's a big difference. $0.45 is still a lot, but it's a lot less than $0.63.

Manitoba Hydro's provided a trend -- tremendous amount of information to substantiate the -- substantiate the need for this rate increase. You can approach your task with a view that the issue is either complex or straightforward. Complex means immersing yourself in 32,000 pages of materials that have been filed to date. Complex means trying to understand and remember every detail. I don't believe it's humanly possible. I don't believe it's necessary.

The key issue is straightforward: Does Manitoba Hydro have enough revenue to operate the business, manage its risks and pay its finance expense. Absent a 7.9 percent rate increase, the answer is clearly no. You don't need to 32,000 pages to answer the key question. In my experience, the having spent really my entire career analysing companies and markets, that a debate about what financial targets are best is really going to be quite difficult to resolve. There are literally dozens of metrics each with their proponents, each with their merits, each with their limitations.

And frankly, for all the blinding pages of numbers - and I'm guilty of showing you more today - there's considerably more art than science to a lot of this. The people I've seen do better at making complex decisions, managing businesses or investing are the ones who don't let a spreadsheet override common sense and accumulated wisdom.

So with that caveat, we thought it was important to maintain some consistency with the metrics the Company has reviewed with this Board in the past, and obviously reports on regularly.

Of our three (3), in our view, the equity ratio is by far the best indicator of whether we are making progress on rate adequacy, sustainability and risk. The real issue and Morrison Park in their review touches on this too, is that our capital coverage and interest coverage ratios are incomplete. They don't capture all of the cash burdens facing Manitoba Hydro, even excluding the

TAB 19

for you still on -- on O&A. And as I understand matters in this GRA, Manitoba Hydro did not have the ability to prepare a detailed operating and administrative expense breakdown. Is that correct?

MS. SANDY BAUERLEIN: Correct.

MR. CHRISTIAN MONNIN: And the reason for that is -- is due to the fact that the full measure and impact of, for example, the voluntary departure program, and other directions are -- are still moving along. Is that correct? They're not come -- they're not finalized yet?

MS. SANDY BAUERLEIN: That's correct. To do a detailed budget, we have to understand exactly where every person is going to be and exactly what function they're going to be doing. With the people leaving, there's still a lot of transition happening across the Company.

MR. CHRISTIAN MONNIN: And my understanding on the evidence to date is that Manitoba Hydro has handled the voluntary departure program and the delimiting of positions internally. Is that correct?

MS. SANDY BAUERLEIN: That is correct. In some cases -- in many cases, the positions are delimited. In other cases, sometimes staff are redeployed to a position that a person may be leaving, but we feel that is a critical role, and that another subsequent follow-on position would be eliminated.

MR. CHRISTIAN MONNIN: And is Manitoba Hydro intending to hire any exterior -- external experts or consultants as it moves along with the workforce reduction plan and the optimizing of the O&M?

(BRIEF PAUSE)

MS. SANDY BAUERLEIN: On some areas may be looking to -- for assistance in trying to manage their specific functions. So while as -- as a company we haven't hired a consultant, there are certain areas that are looking for assistance to help refine some of their -- their processes.

MR. CHRISTIAN MONNIN: Kristen, if you could please go to Appendix 12 -- sorry, 10.12, and page 2 of 5. It's an operational cost and breakdown of benchmarking as prepared by the Boston Consulting Group.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: I'd said 2 of 5. I apologize, it's 4 of 7 on this -- this slide. If you scroll down a little bit, please. As a footnote number 1, it:

"...appears determined by size of global Hyd -- Hydro generation fleet."

Is Manitoba Hydro able to -- other than from that footnote, based on its dealings with Boston Consulting Group, are they -- is Manitoba Hydro able to describe the basis for selecting the utilities, and the numbers of utilities, and whether any of these selective comparatives are verily integrated to prepare this benchmarking study?

MS. SANDY BAUERLEIN: I'm not aware as to what -- how the section process was for the comparison that was done by BCG.

MR. CHRISTIAN MONNIN: And I understand that one (1) of the cost-saving measures that Hydro is looking for it pertains to supply change cost savings?

MS. SANDY BAUERLEIN: That is correct.

MR. CHRISTIAN MONNIN: Has Manitoba Hydro done anything to identify the streamlining and the savings that can flow from that?

MS. SANDY BAUERLEIN: Yes, it does. We have a supply chain initiative which, again, we have identified specific activities, similar to the capital asset management processes. We have different activities happening within different waves.

And as we discussed in the opening presentation, we expect to see -- or achieve savings of around -- a cumulative savings of around 150 million by -- I think it's 2021 -- 20 -- around that timeframe.

MR. CHRISTIAN MONNIN: Are -- are you familiar with what's referred to as a total factor productivity analysis?

MR. JAMES MCCALLUM: I have not heard that term.

MR. CHRISTIAN MONNIN: It represents a study -- the total quantity of outputs of a firm relative to the quantity of all the inputs of it -- that it employs. Is this something that -- anyone in Manitoba Hydro in the panel has -- has heard of in the past?

MS. SANDY BAUERLEIN: I have not.

MR. CHRISTIAN MONNIN: Thank you. I have now some questions with respect to Keeyask.

THE CHAIRPERSON: Sorry, Mr. Monnin,

TAB 20

presentation today, and looking at slide 16, on the -- the second bullet under consistent PUB concern about moral hazards, the domestic customer rates, where it stated:

"Do not want higher rates to reduce Hydro incentive for efficient operation."

I believe -- I took some notes, and I believe you -- your evidence was that staffing -- the staffing complement is -- is still high, notwithstanding the recent cuts that were made.

Is that -- do I recall correct -- correctly?

MR. GERALD FORREST: Correct.

MR. CHRISTIAN MONNIN: And I also understand MIPUG's evidence in -- in Mr. Bowman's prefiled testimony to be that due to the significant scale of changes having recently been imposed, much of the normal details filed in support of O&A forecast is unavailable. Is that fair?

MR. PATRICK BOWMAN: Yes.

MR. CHRISTIAN MONNIN: So when MIPUG is suggesting that these -- this endeavour ought to be supported, what does it mean by that? How would that look, and how would this Board support that -- those endeavours?

MR. PATRICK BOWMAN: Mr. Monnin, my suggestion is that the Board remain vigilant, that the materials Hydro is expected to file and update the board on, and the expectations of the board coming back for its next GRA should make clear that materials detailing the O&M plans and what's been able to be achieved are -- are laid out.

The types of information is not available today because they're in the midst of -- of this type of restructuring, which, as I noted, I don't fault Hydro for at all. But at some point, those changes need to be built into budgets, and that assessments need to be made by looking at those budgets in the context of -- of relevant benchmarks, which both can link to Hydro in the past, or to -- to other utilities' performance.

I -- I made some of the comments in light of -- and I believe the reference is in there, that in light of the fact that there was Board Orders year after year through the 2000s that said, you know, This is -- this is -- you get -- reduce your O&A, reduce your O&A, reduce your O&A. It's not like there's one (1) -- I believe it's in the 2012 Order, where it says, Hydro has added nine hundred (900) people in the time that it's -- it's gotten no difference in its set of functions. You know -- you know -- I -- I don't know if that's a -- a bit of the rationale for the reduction of nine hundred (900) people now is to sort of back out the increases that occurred over that period. But certainly, if you go back to the period they were talking about, to the other -- I believe that was -- that was the 2004 to 2011 period, if I'm not mistaken, 2010.

Even when you go back to the start of that period, 2004, there were comments in a Board Order about -- about keeping O&A under control. So the -- I -- I think the -- the idea is the recommendation should -- should encourage Hydro to follow through, and should encourage Hydro to file the data that this Board can then assess how that turned out, and whether -- whether further pressure is required.

MR. CHRISTIAN MONNIN: And -- and would anyone else on the panel care to add to that?

MR. GERALD FORREST: Treading where angels fear to tread. The unfortunate part in Canada, every utility is structured differently. It is -- some have hydraulic generation with a mix of gas. Some have coal with a mixture of gas and water, and --

and there's a variety of different structures.

The second thing is, geographically, across Canada, we have centres like Toronto, an area that is high concentration of population in a small geographic area, whereas in other parts of the country like Manitoba and Saskatchewan, where we used to -- and I say "used to" -- have probably one (1) or two (2) residents or farms on a particular section of land, now we have maybe one (1) on ten (10) sections of land. So the cost of service to service the customer in, say, Manitoba and Saskatchewan are quite a bit more difficult than it is in some of urb -- other urban communities.

But overall, Patrick is correct, that -- that there needs to be, in my view, inside the organization today, business optimization programming where you look at the most effective way to deliver a service at the least possible cost. At the same time, don't sacrifice safety and reliability in your organization.

MR. CHRISTIAN MONNIN: Thank you, Mr. Forrest. Kristen, if you could please go to MIPUG-14, page 5 of 2 (sic). I hope that I'm driving everyone to the correct page -- 5-2. Yes. Under this bullet number 6, and this -- directed to Mr. Osler and Mr.

TAB 21

of their preferred options, that's what was always the case. So I think it's -- it's reasonable to assume that that's what they were striving to achieve and, clearly, 2027 is much sooner than that.

MR. CHRISTIAN MONNIN: Thank you. And we can all agree that the rate increase that Manitoba Hydro's proposing in these proceedings is 7.9 percent.

MR. PELINO COLAIACOVO: Yes.

MR. CHRISTIAN MONNIN: And would you agree that if Manitoba Hydro's goal was not 75/25 debt-to-equity ratio or if the goal to achieve this target was not ten (10) years rather than give or take the twenty (20) years that was arguably mentioned in the NFAT, is it safe to say that Hydro would not need the proposed 7.9 percent rate?

MR. PELINO COLAIACOVO: I think that's fair.

MR. CHRISTIAN MONNIN: And I understand your evidence, Mr. Colaiacovo, that it's MPI's conclusion that Manitoba Hydro is arbitrarily setting a ten (10) year timeframe for the achievement of the 75/25 debt-to-equity target; is that correct?

MR. PELINO COLAIACOVO: I've used those words, yes.

MR. CHRISTIAN MONNIN: And why -- why

have you used those words arbitrarily setting?

MR. PELINO COLAIACOVO: The explanations given in the application by Manitoba Hydro use the terms "financial strength" repeatedly and use the terms "unacceptable risk," but without providing numerical demonstration that, you know, what the probability of the occurrence of that unacceptable risk is, that would require such an extraordinary rate increase and -- and certainly such an extraordinary repetition of rate increases.

In the NFAT process there was a lot of time and effort spent on showing that rate increases at two (2) times the rate of inflation were going to be sufficient to -- to pay for their preferred development plan. Many, many scenarios were run and -- and there was some discussion about that earlier today. And in a very, very small number of scenarios it -- you know, we demonstrated in our own analysis that two (2) times the rate of inflation might not have been enough, right. But those were a very very small number of potential cases.

Now in the application, Manitoba Hydro has asked for four (4) times the rate of inflation because the previous paths were unacceptably risky. But what does that actually mean? And it -- it doesn't appear from the material that we read that they've provided any clear logical links between the data and the request other than -- than using terms like "unacceptably risky." What threshold of probability is unacceptably risky? What threshold of consequences are unacceptably risky? Yes, there are cases where 4 percent, for example, two (2) times the rate of inflation is not enough.

But how many cases, under what scenarios and what is the likelihood of those occurring and should you be raising rates by four (4) times the rate of inflation because there is, for example, a 5 percent probability of that scenario arising? Should you raise rates if there's a 10 percent scenario? Should you raise rates if there's a 20 percent probability? They haven't talked about any of that.

They've simply said, we want to raise rates at four (4) times the rate of inflation to achieve this target by 2027, because the alternative is unacceptably risky. To me, if you don't provide the data, if you don't provide thresholds, if you don't provide analysis, it's arbitrary.

MR. CHRISTIAN MONNIN: Thank you. And in addition to that, Morrison Park draws a conclusion that setting since arbitrary ten (10) year timeframe is particularly insupportable; is that correct?

MR. PELINO COLAIACOVO: Yes.

MR. CHRISTIAN MONNIN: And that is on account of this arbitrary timeframe being set in the face of massive investments in new projects, is that correct?

MR. PELINO COLAIACOVO: Yes.

MR. CHRISTIAN MONNIN: And what this arbitrary timeframe is doing is effectively requir -- requiring today's ratepayers to contribute in the next ten (10) years, 25 percent of the full amount spent to date on Bipole III, Keeyask and related projects; correct?

MR. PELINO COLAIACOVO: That's correct.

MR. CHRISTIAN MONNIN: In addition it's asking today's ratepayers to contribute in the next ten (10) years, 25 percent of all the remaining produc -- all the remaining projects until they are completed, that is Bipole, Keeyask, et cetera.

Is that correct?

MR. PELINO COLAIACOVO: Yes.

MR. CHRISTIAN MONNIN: I understand your evidence is that Keeyask and Bipole are two (2) of the largest projects Manitoba Hydro's ever seen; is that safe to say?

MR. PELINO COLAIACOVO: Yes, it is.

MR. CHRISTIAN MONNIN: And Mr. Colaiacovo, in view of that what would you -- be your response to the argument that imposing the proposed rate increases are -- that we're dealing with today, and the timeframe on ratepayers is what is consistently and normally done from time to time with a publicly owned verti -- vertically integrated electrical Utility?

MR. PELINO COLAIACOVO: Yes, I think Manitoba Hydro itself has a history where they built large projects. Other similar Utilities build large projects from time to time and have to face the same challenges. How do you -- how do you integrate that large project into your balance sheet and your rates over time so that it's fair and balanced.

MR. CHRISTIAN MONNIN: And what is being proposed -- are you able to -- to provide an opinion, is this fair and balanced in light of the fact that we're dealing with two (2) of the largest projects that Manitoba Hydro's ever seen?

MR. PELINO COLAIACOVO: So after our own analysis of the risks and -- and our own analysis of the evidence about those risks, in our view, the case has certainly not been made that the 7.9 -- a series of 7.9 percent increases are required to manage the risks that -- that they have indicated are out.

MR. CHRISTIAN MONNIN: I'd like to ask you a few questions about the export market for Manitoba Hydro.

My understanding is -- your evidence is that Manitoba Hydro is the only Utility which combines a full cost recovery model with an explicit mission to develop electrical -- electricity resources for export purposes?

MR. PELINO COLAIACOVO: That's correct.

MR. CHRISTIAN MONNIN: And would it be -- would you agree with me if I suggested that the decision to develop Keeyask to a certain extent forms part of that mission?

MR. PELINO COLAIACOVO: I -- I think that's absolutely true in the -- in the NFAT process there was a discussion about the -- the choice of building Keeyask earlier or later.

If Keeyask was built earlier then most of the output from Keeyask in the early years would go to exports and, in fact, Manitoba Hydro put a lot of

TAB 22

Principles of Public Utility Rates

Second Edition

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PART FOUR

THE RATE STRUCTURE

In the introduction to Part Three we distinguished between the determination of a company's general level of rates, and the determination of specific rates or rate relationships. However, it was emphasized that the distinction between rate-level and rate-structure is one of convenience rather than of analytical logic. In the words of the late Chief Justice Stone (1942, p. 575, 584), speaking for the Supreme Court in *Federal Power Commission v. Natural Gas Pipeline Company*,

> The establishment of a rate for a regulated industry often involves two steps of different character, one of which may appropriately precede the other. The first is the adjustment of a general revenue level to the demands of a fair return. The second is the adjustment of a rate schedule conforming to that level, so as to eliminate discriminations and unfairness from its details.

Thus, the chapters of Part Three were concerned with rate-level determination under the standard of a fair return. Now we turn to a discussion of the far more complex problems involved in establishing an appropriate rate-structure.

The complexity of the rate structure is due partly to the mass of technical detail; this includes the rapidly advancing, but still constraining, technology of metering that is involved in the design and administration of workable rate schedules for different types of utility enterprises. It is also due to the inability of the ratemaker to predict the effects of changes in rates on the demand for service and hence on costs of supply — due, in short, to incomplete and/or unreliable information about demand functions and cost functions. Finally, and this is the ponderable theoretical difficulty, it is due to the necessity, faced alike by public utility managements and by regulating agencies, of taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure.

In view of the complexity of subject matter, the present study will not undertake descriptions of the typical rate structures of the different types of public utilities. The reader unfamiliar with these structures is therefore referred to studies like those of Garfield and Lovejoy (1964), *Gas Rate Fundamentals* (1978), and Phillips (1984, Chapters 10 and 11). A reader unfamiliar with the structure of public utility rates as presented at a more elementary level may find our discussion of general principles hopelessly abstract. Even in its treatment of principles, these chapters should be regarded only as essays on the nature of the more controversial, largely unresolved, problems rather than exhaustive surveys of the voluminous literature on this subject. But they all have one theme in common: that the most formidable obstacles to further progress in the theory of public utility rates are those raised by conflicting goals of ratemaking policy. In this part we address two essential questions: (1) what specific rates will yield a fair return; and (2) what rates and rate relationships should be chosen when a company's earning power is so high that any one of a variety of tariffs could be made to yield adequate over-all revenues? The answers to these questions require the adoption of a set of objectives and the development of criteria by which to judge a sound rate structure.

This is one of the primary purposes of Chapter 16. While recent events in some areas of economics, including the field of indirect regulation (i.e., antitrust), may lead one to believe that economists have a monolithic dedication to one standard — viz., economic efficiency — this is decidedly not the orientation of this study. While economists have been characterized as having a "passionate irrationality for dispassionate rationality", this does not preclude our recognition of appropriate quasi-economic and noneconomic factors in actual ratemaking.

However, for the most part, we do assume an unqualified priority to the fair-return standard of reasonable rate levels, despite the fact — noted in Chapter 10 — that no such priority is necessarily accorded by legal doctrine or ratemaking practice. That is to say, we assume that the rates of any given utility enterprise, taken as a whole, must be designed, in so far as possible, to cover costs as a whole, including a fair return on capital investment. Moreover, we assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services that are demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of market power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit. Except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs.

Without doubt, the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. Thus, we adopt the objectives that were first specified in Chapter 5 as the basis for developing a sound rate structure. However, deviations from a cost-of-service standard may be necessary under a variety of conditions that are often found in practice. In Chapter 16 we list ten attributes of a sound rate structure. Some of these are related directly to the objectives, whereas others may be regarded as deviations from a strict cost standard. Three of the attributes relate to the provision of adequate and stable revenues and rates; five others are based on cost considerations, and the remaining two deal with practicality and acceptability. However, these attributes are unqualified to serve as a basis for sound ratemaking policy because of their conflicting nature and the fact that there are no priorities among them.

In Chapter 17 we introduce the vitally important subject of marginal cost. This term, or one of its approximate synonyms such as incremental cost, is itself a highly ambiguous term, with the result that proposals to base rates on marginal costs mean different things to different people. The most important ambiguity is that suggested by the distinction between short-run and long-run marginal costs. This distinction is of some importance, for most of the differences between incremental and average costs of public utility services are those which apply only when incremental costs are taken to be of a short-run variety. Nonetheless we contend that the difference between cost and noncost standards and between marginal cost and nonmarginal cost standards are more significant than the differences between long-run and short-run marginal costs.

One of the first tasks in Chapter 17 is therefore to discuss the distinctions between these two types of marginal cost. Most of these distinctions would apply, with modifications, to short-run versus long-run incremental costs in general and not alone to costs of increments so small that they are called "marginal." Some economists have gone so far as to propose the acceptance of marginal-cost-based rates even when, in consequence, the resulting revenues will fail to cover total costs and must therefore be supplemented by a tax-financed subsidy. The merits of this unorthodox proposal are discussed briefly in Chapter 18.

However, even under the traditional principle that "rates as a whole should cover costs as a whole," marginal cost should play an important role in the design of rates and rate relationships. In fact, it may play a dual role: first, in setting a lower limit below which no rates will be fixed, not even in order to promote the use of service which could not otherwise find a buyer; and secondly, in serving as a basis for relative rates, subject to deviations of a value-of-service or Ramsey pricing nature. These two uses of marginal cost estimates are developed in Chapters 17, 18 and elaborated in Chapter 20.

The more traditional alternative to modified marginal cost pricing is that of a fully distributed cost methodology. Under this method rate structures are derived in a two-step process known as cost allocation and rate design. The former involves an assignment of revenue responsibility — the revenue allocation — under the assumption that rates should be based solely on costs. The second step is an apportionment intended to determine the pattern of each rate class.

What significance should be attached to these fully distributed costs as guides for rate determination? Public utility managements and public service commissions have often denied or doubted the value of comprehensive total-cost apportionments even as useful guides to rate design. This adverse or skeptical attitude may well be justified, but one should not condemn the procedure too hastily, for it is not devoid of at least a *plausible* rationale. What, then, is this rationale? This is the primary question discussed in Chapter 19.

Chapter 20 deals with the emotionally-charged issue of discrimination. Certain types of discrimination are expressly outlawed without qualification by statute, regardless of the prevailing *Weltanschauung*. But the law does not forbid all forms of discrimination, and commissions may tolerate forms or degrees of discriminatory ratemaking that they might otherwise forbid in order for a company to maintain sound corporate credit. However, there is a good deal of confusion about exactly what constitutes discrimination as defined by economists and noneconomists. So one of the tasks is to define what constitutes discrimination, due or undue. A central point we emphasize is that discrimination is a cost-related concept. It is cost related in the sense that differences in rates are discriminatory only to the extent that they deviate from marginal costs. Moreover, arguments can be made in support of discriminatory rates based on "Ramsey" rules because, under certain conditions to be specified in Chapter 20, they can be used to enhance welfare. We also explore briefly the relatively new and untested area of axiomatic cost pricing in this chapter.

CHAPTER 16

CRITERIA OF A SOUND RATE STRUCTURE

The design of electric rates has recently emerged from the closet of regulatory neglect to a new prominence. (Cudahy and Malko, 1976, p. 47.)

INTRODUCTION

Public utility counsel have sometimes argued that once a company's total revenue requirements have been determined by a commission, the choice of a pattern of rates that will yield the allowed revenues should be left to the discretion of management, which will then be in an impartial position to make a fair apportionment of burdens among its different classes of ratepayers. This is only a half-truth because, among other reasons, a utility company is concerned not just to secure rates that will presently yield the approved fair rate of return, but to develop a pattern of rates that will promote growth of earnings and that will protect these earnings against adverse business conditions. The better the utility management, the greater are these concerns.

Historically, state public service commissions have given more attention to rate relationships than to rate levels. Their primary concern with specific rates was to provide favorable treatment to residential customers. However, the energy price increases of the 1970s and the increasingly competitive environment in all the utility industries during the 1980s has resulted in even more active intervention by organized residential consumer groups and very large industrial customers, with greater concern with specific rates on the part of the regulatory commissions. A plausible reason for the reluctance on the part of a commission to override the rate-pattern policies of a utility company is the one suggested many years ago by Watkins (1921, p. 37), in expressing regret that few American commissions had contributed substantially to the development of principles of electric-rate design. "This situation," he wrote, "is perhaps partly due to doubt as to the possession of adequate powers, but more fundamentally to the diffidence of commissioners when confronted with a subject so complex, both theoretically and practically, as that of electric rates." The commissions that have given the most attention to rate-structure principles are the stronger commissions, such as those of California, New York, Wisconsin and others, which have the aid of relatively large expert staffs.

Essential Questions in Rate Design

Even if the determination of revenue requirements under a fair-return standard were taken as the master rule of ratemaking, there would still remain two essential questions:

> (1) what specific rates will yield a fair return, and
>
> (2) what rates and rate relationships should be chosen when a company's earning power is so high that any one of a variety of tariffs could be made to yield adequate overall revenues?

We turn now to principles of ratemaking designed to throw light on these two questions, but particularly on the latter. By what basic standards, for example, shall regulation pass judgment on a system of electric-utility rates which allows liberal discounts for incremental blocks of energy; or which levies higher charges, per kilowatt-hour, on residential than industrial ratepayers; or which concedes lower rates for off-peak consumption than for consumption at peak-time hours or seasons? And what are the merits of the contentions that natural gas should be priced higher for customers who receive gas on a firm, as opposed to an interruptible, basis? With the telephone utilities, does public policy justify the practice of the industry in setting higher rates for service offered in larger urban communities than for comparable service in small, often rural, communities even when these differentials are not based on differences in cost of service? These are mere random samples of the many practical issues falling under the subject of rate structure. Let us examine one of these in more detail.

Historically, rates for local telephone service have been based on a value of service standard. In particular, the rates for service in rural areas are generally less than the rates in the urban areas. The reason for this was that it was believed the service in the urban areas was more valuable since the subscribers had a larger number of people in their local calling area. This application of value-of-service pricing totally disregards the fact it is more costly to provide telephone service in the rural areas than in urban areas. In Nebraska, for example, in 1988 the local rate for Northwestern Bell in Omaha was $15.68 per month (including local usage and taxes) and the cost for just the local loop was $14.30. Home Telephone, a small company serving a rural Nebraska community, charged $4.50 per month (including local usage and taxes), but the monthly cost for just the loop was $23. In order to make each company solvent, long distance rates were averaged which allowed rural companies to offer service below cost. The result of this was that companies in the rural areas were subsidized by ratepayers in the urban areas through long distance rates.

However, when the move to competition in the industry began, policymakers recognized the incompatibility of competition and cross subsidization. In Docket 78-72, the Federal Communications Commission (FCC) began the move towards cost-based pricing and to phase out cross subsidies. However, since rural companies were faced with large rate increases the FCC established a plan designed to protect these companies. Under this plan, the FCC established the Universal Service Fund, allowing high cost companies to assign part of their costs to toll service and thereby partially continue the subsidy from urban areas.

Complexity of the Issues

In this chapter we mostly emphasize a normative theory about what should be done as opposed to positive theory about how the world is. One of the paramount normative issues is rate structure. Rate-structure problems are far more complex than problems of a fair return, even though the latter are by no means elementary; and they are even less amenable to solution by reference to definite principles or rules of ratemaking. In part, the complexity is due to the mass of technical detail, including the technology of metering, involved in the design and administration of workable rate schedules for different types of utility enterprises. In part it is due to the inability of the ratemaker to predict the effects of rate changes on demand and hence on costs of supply — due, in short, to ignorance of demand functions and cost functions. But in part — and this is the theoretical difficulty — it is due to the necessity, faced alike by public utility managements and by regulating agencies, of taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure. The nature of some of these conflicts will be revealed as this discussion proceeds. But, by way of illustration, we may note the conflict between the desirable attribute of simplicity and the otherwise desirable attribute of close conformity to the principle of service at cost. Here, as with other clashes among various desiderata of ratemaking policy, the wise choice must be that of wise compromise; and in reaching this compromise, the practical rate expert would look in vain to any general theory of public utility rates for a scientific method of reaching the socially optimum solution. An economically rational approach would involve comparing the benefits with the costs, but this is not always easy or even feasible. For instance, measuring the intangible costs of time-of-use metering cannot be readily assessed. Needless to say, no one has supplied a formula by which to draw the line between too much and too little simplicity.

A recurring theme of this book is that there are conflicts among the competing objectives of ratemaking that are difficult to resolve, thus making the climb to the peak of Mount Pareto slippery. While our preference as economists is to make greater use of the criterion of service at cost as the standard by which alternative rate structures are compared, we realize that to expect this bias of others would be hopelessly naïve. We do believe, however, that the ratemaker should utilize the cost standard as a benchmark, with assessments of the efficiency advantages (or disadvantages) of particular rate structures playing a subsidiary role; social and fairness standards also may be appropriate within the limits of authority that a regulating body may be able to exercise. As the French thinker Blaise Pascal noted: "We know the truth not only by reason, but also by the heart."

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting criteria of reasonable rates and rate relationships, an intelligent choice of these depends primarily on the accepted *objectives* of ratemaking policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. However, no rational discussion of the relative merits of cost of service and value of service, for example, as standards of desirable rates or rate relationships is possible without reference to the question of what desirable results the ratemaker hopes to secure, and what undesirable results are to be minimized, by a choice between or mixture of the two standards. This was recognized explicitly in the Electric Utility Rate Design Study sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and undertaken by the Electric Power Research Institute (EPRI) (See Malko, Smith and Uhler, 1981, p. 1-6). Not only this: the very *meaning* to be attached to ambiguous, proposed standards such as those of "cost" and "value" — an ambiguity not completely removed by the addition of familiar adjuncts, such as out-of-pocket costs, or marginal costs, or average costs — must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

In this section we first outline a set of attributes to be sought in the development of a sound rate structure. While we know that regulation will not guarantee good economic performance, we should at least like it to arrest or curb egregiously bad performance. For instance, regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions. Sound rate relationships are essential to the attainment of these desirable ends, but criteria are required to judge whether, and to what extent, these objectives have been attained. In our attempt to put the competing criteria into an explicit form we recognize that we are violating the sage advice of Charlie Brown that: "No problem is so big that it can't be run away from."

Attributes of a Sound Rate Structure

What are the attributes to be sought in the development of a sound rate structure? Many different answers have been suggested in the technical economics literature and in the reported opinions by courts and commissions. A number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the canons of taxation found in Adam Smith's *Wealth of Nations* (1937 — originally 1776) and subsequent treatises on public finance. In very general terms (see e.g., Federal Energy Regulatory Commission, Order No. 436, October 9, 1985) optimal rates: should provide clear, efficient, effective, informative, and cost-effective market signals about the present and the future cost of service to buyers and sellers, (which requires that prices track costs); should embody strong incentives for optimal present and future cost and service quality configuations; should give buyers and sellers optimal flexibility in selecting sellers and buyers respectively; should allow utilities to serve as agents of progress; should maintain or improve distributive equity, and should allow for the attainment and maintenance of a flexible (non *ad hoc*) regulatory framework with a modicum of necessary delay and obfuscation (and even a willingness of a commission to dissolve itself under the appropriate competitive or contestable conditions!). But this is a pretty general menu, and more specific direction is needed when applying them to an empirical world. As someone once said, "the real world is only a special case of the theoretical world, and not a very interesting one at that." But many practical-minded people would disagree, so let us push on to greater specificity.

The list that follows is fairly typical, although we have derived it from a variety of sources, instead of relying on any one presentation. Of the ten proposed attributes enumerated in this section, the first three relate to the provision of adequate stable and predictable revenues and rates; the next five are based on cost, efficiency, and equity considerations, and the remaining two deal with matters of practicality and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of ratemaking policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, the following three may be called primary, not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto: (1) the revenue-requirement, production-motivation, or financial-need objective; (2) the optimum-use, demand control, or consumer-rationing objective; and (3) the compensatory income transfer function or fair-cost-apportionment objective. Based on these objectives we propose the following three primary criteria by which to judge the soundness and desirability of a rate structure for public utility enterprises. As outlined below, these objectives are related closely to five of the ten attributes specified above.

Criterion 1 - Capital Attraction

(Attribute 1): based on the revenue-requirement objective, with due regard to potential problems of socially undesirable levels of rate base, product quality, and safety; it takes the form of a fair-return standard with respect to private utility companies;

Criterion 2 - Consumer Rationing

(Attributes 4 and 5): based on the consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received;

Criterion 3 - Fairness to Ratepayers

(Attributes 6 and 7): fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination.

The objectives specified above correspond to three of the four primary functions of utility rates set forth in Chapter 4. The efficiency-incentive function, or that of encouraging managerial efficiency, is omitted because of its more direct bearing on the desirable criteria for a fair rate of return. Some writers, especially the older ones, e.g., Wallace (1941, pp. 475-478) would add a fifth objective: that of benefitting specific classes of ratepayers, such as customers of substandard income or a depressed industry. This objective comes under the heading of social principles of ratemaking as we have used the term in Chapter 8.

In actual rate cases, these three objectives of reasonable rates and rate relationships, and particularly the last two, are by no means always sharply distinguished. But the distinction may be illustrated by the imagined example of a request, submitted to a regulating commission by a group of ratepayers, that an electric (gas or telecommunications) company be ordered forthwith to abandon its present, somewhat elaborate, schedule of class rates, block rates, and two-part or three-part tariffs in favor of a uniform kilowatt-hour (therm or message minute) rate for all customers throughout its franchise territory. Almost certainly this proposal would be held subject to the threefold objection:

(a) that no uniform rate, however high, could be made to yield a fair return on the company's invested capital;

(b) that, even if it could do so, rate uniformity despite lack of cost uniformity in the supply of different types of service would impose *unfair* and discriminatory burdens on the consumers of the less costly services; and

(c) that, quite aside form its unfairness, the uniform rate would result in a serious underutilization of plant capacity because it would cut down the demand for services (especially, for off-peak services) that could be supplied at incremental costs materially below average unit costs, while stimulating a wasteful on-peak demand for services that can be supplied only at incremental costs higher than average costs and it does not reflect any differential social costs and benefits in different areas.

Some writers who confine their attention to what they call the "economic" principles of public utility rates have ignored the third criterion of a sound rate structure in their development of their principles of public utility rates on the ground that fairness questions are beyond the competence of professional economists (on the general issue of fairness, see Zajac, 1985, and Baumol, 1986). Instead, they have centered attention on the second criterion, often with special reference to its application under the constraint of a revenue-requirement constraint. But a refusal to recognize fairness issues as relevant to the design of a sound rate structure would so far remove the analysis from the objectives of Chapter 5 and divorce theory from practice that these issues will not be completely ignored in the discussion that follows.

Stability and Predictability of Rates: A Secondary Criterion

Attributes 2 and 3 on stability and predictability have been neglected relative to those associated with the three primary criteria, and deserves further consideration. In ratemaking, the attribute of *predictability*, is more important than *stability* per se. Time-of-use rates, for example, are not stable (in a strict sense), but are predictable and, most would agree, desirable. One could certainly argue that ratepayers should be given the information they need to *predict* rates accurately. However, this does not imply a necessary need to keep rates stable at the expense of otherwise efficient pricing. For instance, in the case of rate base valuation, most jurisdictions opted for the rate stability associated with original costs (also for the popular understanding and administrative practicality) even though this method has an economic cost in terms of ideal resource allocation and use during periods of changing price levels. In that case, the presumably intelligent choice between the merits and demerits of the alternatives led decisionmakers to conclude that the price society pays for this stability is reasonable.

Stability, like freedom, is not free. Utility regulation can and does affect the social cost of risk bearing (Schmalensee, 1979, p. 36-37). The bearers of risks have real costs imposed on them. Economic efficiency calls for the one's best able to bear risk to do so. Ideally, the regulatory process only redistributes and does not increase total risks. Erratic regulation can increase a firm's real costs, including capital costs. Stabilized rates (returns) shift risks from ratepayers (shareholders) to shareholders (ratepayers). Utilities need revenue stability to mitigate the sunk costs of their highly specialized systems that make them prime candidates for expropriation or opportunism. However, as Yandle (1987) puts it: "You can fleece a sheep many times, but you can only skin him once."

A monolithic critic might ask: why place such great importance on revenue and rate stability and predictability when no such constraints operate in the unregulated sector (especially in light of the business cycle)? The answer to this question is provided in great detail in the next two chapters. For the moment, let it suffice to note five major considerations. First, some users have a strong preference for rate stability in planning even if it means some sacrifice in the (higher) level of initial rates. This is especially true of customers who use the utility in the production of other goods and services and who fear that rivals may obtain advantages by acquiring the service more cheaply and reliably elsewhere (Baldwin, 1987, p. 225). Second, there are transaction costs involved in the determination, administration, and publicity of a rate structure; these include advertising, publishing and distributing price lists, issuing new catalogs, etc. Third, since the greater asset-specificity in regulated markets provides more scope for opportunistic behavior, assurances of predictable revenues are appropriate in a regulated industry. Fourth, rate stability and more particularly predictability, are needed to allow the users to secure a rational control of demand. We want to make sure that regulation does not increase, but only redistributes the total and real risk. Therefore, a fourth criterion, although of a somewhat lower rank than the three primary ones discussed earlier, is that of stability and predictability of specific rates and of revenues.

Some Simplifying Assumptions

In the remainder of this Part Four, except for the sections in Chapter 17, the principles governing the development of a sound rate structure will be discussed under the assumption that rates are designed primarily to subserve the four primary objectives of ratemaking policy specified earlier. But in order to avoid extreme complexities, the following four explicit assumptions are made, all of which are implicit in much of the literature on public utility rates. Some of these are reiterations of the criteria, whereas others are additional assumptions required for clarity.

In the first place, we shall impute an unqualified priority to the fair-return standard of reasonable rate levels despite the fact, noted in Chapter 10, that no such priority is accorded either by legal doctrine or by ratemaking practice. That is to say, we shall assume that the rates of any given utility enterprise, taken as a whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

In the third place, throughout this handbook, we operate under a general presumption that pricing at marginal cost would lead to a revenue shortfall; i.e., the firm operates in the range of declining unit costs. However, there is evidence now to suggest that there are certain aspects of utility operations, such as the generation of electricity, which are in the range of increasing unit costs. Thus, the possibility exists that a company could find itself overall in the increasing cost range. This nontrivial possibility should be kept in mind in discussions of the problem of revenue reconciliation.

And in the fourth place, except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs. While the rate structure may be used as a tool for redistributing income, economists in general prefer alternative fiscal policies, such as taxation and direct subsidies. This is so primarily because of the limited span over which any single regulatory body may exercise control. Thus, the positive realities impinge on our normative analyses.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Cost-of-service as a Basic Standard

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. For example, based on their extensive researce associated with the Electric Power Research Institute (EPRI) rate design study, Malko, Smith and Uhler (1981, Chapter 4) conclude that "In general, cost-based rates satisfy the commonly held multidimensional, sometimes conflicting, pricing objectives better than noncost-based rates". In the literature, the cost-of-service measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various social objectives of ratemaking. However, Stanley (1984) argues that because of the interdependency among ratepayers of basic service and the deterrence effects of the connection charges — e.g., access to the telephone network — the optimal price would be set *below* marginal cost with subsidization by nonbasic services such as the Yellow Pages, Touch-Tone service, long-distance service, etc. Be that as it may, in actual practice there is usually an obvious, marked to meet separate tests of financial self-sufficiency, project by project. (See especially Vickrey, 1955, who has been one of the leading American authorities on marginal-cost pricing in its application to public utilities.) Where optional routes are available for trucks and automobiles, the resulting mixture of high-toll, low-toll, and no-toll routes is almost sure to lead to serious economic wastes, because it motivates the road users to base their choices on relative money costs that do not reflect relative social costs. This same problem is evident in the determination of electric and natural gas rates in separate proceedings before a regulating commission.

But the toll-bridge illustration is merely a simple example of the asserted advantages of marginal-cost pricing over full-cost pricing applicable to all public utilities — applicable, in short, to a vitally important group of noncompetitive industries with respect to which the gap between the two types of pricing is especially wide. To be sure, marginal costs even of a short-run variety are less likely to be merely trivial for these other utilities than for toll bridges. Moreover, opportunities for rate discrimination, such as with Ramsey pricing, as a means of full-cost recovery are likely to be much better. But the general principle still applies.

And, as to the use of discrimination as a device by which to jump the gap between average-cost and marginal-cost standards, Hotelling cites some unhappy consequences of the attempts by railroads to make these jumps as failing to justify any complacency toward this device for the attainment of essentially inconsistent advantages.

Critique of Proposal to Fix Rates at Short-run Marginal Costs

Reserving for a later section a discussion of the much milder proposal to base rates on marginal costs of a long-run character, let us now consider critically the merits of the far more drastic proposal to base rates on short-run marginal costs. Already some of the more serious objections have been noted in Chapter 17, which discusses the relative merits of the two major types of marginal costs as measures of *minimum* rates. Harbeson (1955) presents a well-balanced critical appraisal of marginal-cost pricing, both of the short-run and the long-run varieties. Harbeson comments on one criticism not yet discussed in this chapter: that the supporters of marginal-cost pricing for regulated monopolies ignore the supposed failure of unregulated prices to come into accord with the marginal costs under the most widely prevailing types of competition, namely, imperfect competition. On the other hand, Andersson and Bohman (1985) note many shortcomings on the concept of long-run marginal costs.

Measurement and Related Problems. First, let us recall that, with most public utilities, the really significant choice is not a simple choice between *marginal* cost and *average* cost as the basis of ratemaking. To be sure, the assumption that the ratemaker faces this dire dilemma is not too far from reality in the toll-bridge example, since here the practical opportunities for rate differentiation are severely limited. Hence the bridge example presents an unusually forcible case for the adoption of marginal-cost pricing or, at least, for the abandonment of any attempt to make each particular bridge rest on its own financial foundations. But with most other utilities there exists a wide variety of plausible rate structures, including those which resort to multi-part ratemaking, block ratemaking, and various forms of discriminatory pricing. Most of the rate structures now in effect are subject to material improvement with advances in the technique of rate design but without abandoning the total-cost principle. While none of them can be expected to have *all* of the consumer-rationing advantages of unqualified marginal-cost pricing, neither can they be assumed to result in economic losses of the order of magnitude of those suggested by an attempt to make a particular toll bridge financially self-sufficient through a uniform charge of so many cents or dollars per vehicle per crossing. Unfortunately, however, the measures of the relative gains and losses of marginal-cost pricing versus any given type of discriminatory, full-cost pricing that are suggested by economic theory are impossible to apply in terms of present factual knowledge. Also remember that the relevant marginal costs must also include the measurement or metering cost which, for example, accounts for for 10-25 percent of the cost of the average measured telephone call, depending on the type of serving equipment (Berryhill and Reinking, 1984).

Importance of Stability of Rates. Secondly, we must consider whether or not the almost undeniably superior efficiency of short-run marginal-cost pricing as a means of securing the optimum utilization of a plant of temporarily redundant capacity warrants the surrender or impairment of all of the other important functions of utility rates, even the function of aiding in the control of the demand for and supply of utility services in the longer run. Even this claim of superiority must be conceded only on the assumption that the better-than-nothing use of temporarily excess capacity will not materially interfere with possible emergency use. Instant readiness to serve may well be the best use of idle capacity. Clemens (1956, pp.92-93) had this point in mind in doubting the wisdom of proposed attempts by electric utilities to encourage three-shift factory loads by the concession of very low rates for off-peak industrial service (1956, pp. 92-93). To the same effect, see Hutt (1939), and Troxel (1950). Resort to three shifts, Clemens recalled, was one of the major ways by which the country avoided a menacing power shortage during the Second World War. "One day's loss of lives," he added, ". . . constitutes quite a lot of marginal disutility."

By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time. For it is the anticipated, fairly long-run costs of service which potential ratepayers wisely take into account when they face a decision whether to commute from Nowhereville to Somewhereville despite the daily payment of tolls on the Goingsomewhere Bridge; or whether to equip their homes with an electric range or with electric air conditioning; or whether to locate their aluminum plants on the Elysium River rather than in the state of Nirvana. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the own price elasticity of demand for utility services can be expected to be much greater in the fairly long run than in any very short period of time. But if utility rates were to be made as volatile as may be required by the mandate of conformity to short-run marginal costs, they would deprive consumers of those expectations of reasonable continuity of rates and of rate relationships on which they must rely in order to make rational advance preparations for the use of service. But even apart from the frequent rate fluctuations that would be necessary if there were frequent changes in short-run marginal costs that make it difficult to respond intelligently and quickly, there is another limiting factor. "On a mere mechanical level, there is always the cost involved in the determination, publication and administration of a rate structure." (Vickrey, 1955, p. 605). It is mindboggling to think of all the combinations and permutations of marginal-cost pricing that would be forthcoming if all the possibilities involved were considered, i.e., various generating stations, customer load centers, several voltage levels, and, perhaps most important of all, the fact that there are 8,760 hours in a year (Cicchetti 1975). But, once again the rational thing to do is to consider the estimated incremental gains from the stability and predictability of rates against the probable incremental costs of achieving other desirable criteria of a sound rate structure.

TAB 23

2015 SCC 45, 2015 CSC 45
Supreme Court of Canada

ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)

2015 CarswellAlta 1745, 2015 CarswellAlta 1746, 2015 SCC 45, 2015 CSC 45, [2015] 3 S.C.R. 219, [2015] A.W.L.D. 3680, [2015] A.W.L.D. 3682, 20 Alta. L.R. (6th) 292, 21 C.C.P.B. (2nd) 1, 257 A.C.W.S. (3d) 728, 388 D.L.R. (4th) 515, 475 N.R. 83, 602 A.R. 1, 647 W.A.C. 1, J.E. 2015-1511

ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd., Appellants and Alberta Utilities Commission and Office of the Utilities Consumer Advocate of Alberta, Respondents

McLachlin C.J.C., Abella, Rothstein, Cromwell, Moldaver, Karakatsanis, Gascon JJ.

Heard: December 3, 2014
Judgment: September 25, 2015
Docket: 35624

Proceedings: affirming *ATCO Utilities, Re* (2013), 7 C.C.P.B. (2nd) 171, 93 Alta. L.R. (5th) 234, (sub nom. *Atco Gas and Pipelines Ltd. v. Alberta Utilities Commission)* 584 W.A.C. 376, 556 A.R. 376, 2013 ABCA 310, 2013 CarswellAlta 1984, Frans Slatter J.A., Peter Costigan J.A., Peter Martin J.A. (Alta. C.A.); affirming *ATCO Utilities, Re* (2011), 2011 CarswellAlta 1646, Anne Michaud Chair, Bill Lyttle Member, Moin A. Yahya Member (Alta. U.C.)

Counsel: John N. Craig, Q.C., Loyola G. Keough, E. Bruce Mellett, for Appellants
Catherine M. Wall, Brian C. McNulty, for Respondent, Alberta Utilities Commission
Todd A. Shipley, C. Randall McCreary, Michael Sobkin, Breanne Schwanak, for Respondent, Office of the Utilities Consumer Advocate of Alberta

Subject: Corporate and Commercial; Public; Employment
Related Abridgment Classifications
Public law
IV Public utilities
  IV.5 Regulatory boards
    IV.5.b Regulation of rates
Public law
IV Public utilities
  IV.5 Regulatory boards
    IV.5.d Miscellaneous
Headnote
Public law — Public utilities — Regulatory boards — Miscellaneous
Regulated companies applied to include their full pension costs in their revenue requirements — Companies argued that their pension policies were prudent, made in good faith by third party, and consistent with industry standards, and that they should be allowed to include all of their pension costs in their rates — Utilities commission denied companies permission to include certain pension costs in their estimates of revenue requirements — Commission found that evidence did not support finding that awarding in every year annual cost of living adjustment (COLA) award of 100 per cent of consumer price index up to three per cent was acceptable standard practice — Companies appealed — Appeal was dismissed — Court of Appeal ruled that analytical framework selected by commission was not unreasonable — Two-stage analysis of determining if expenditures were prudently incurred and then setting of reasonable rates was not mandated — On record, it was open to commission to determine that only 50 per cent of COLA amounts should be

included in rates — Reasons for decision explained adequately how commission came to that conclusion, and there was no basis for appellate intervention — Utility companies appealed — Appeal dismissed — Standard of review was reasonableness — Regulatory framework allowed commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses but does not impose specific rate-setting methodology — Commission itself must decide upon specific test and methodology to employ — There is no obligation on commission to utilize particular prudence test methodology when reviewing costs on forecast basis — Utility bears onus of proving that tariff it proposes is just and reasonable — Both methodology commission used, and application of that methodology, were reasonable given nature of costs.

Public law --- Public utilities — Regulatory boards — Regulation of rates

Regulated companies applied to include their full pension costs in their revenue requirements — Companies argued that their pension policies were prudent, made in good faith by third party, and consistent with industry standards, and that they should be allowed to include all of their pension costs in their rates — Utilities commission denied companies permission to include certain pension costs in their estimates of revenue requirements — Commission found that evidence did not support finding that awarding in every year annual cost of living adjustment (COLA) award of 100 per cent of consumer price index up to three per cent was acceptable standard practice — Companies appealed — Appeal was dismissed — Court of Appeal ruled that analytical framework selected by commission was not unreasonable — Two-stage analysis of determining if expenditures were prudently incurred and then setting of reasonable rates was not mandated — On record, it was open to commission to determine that only 50 per cent of COLA amounts should be included in rates — Reasons for decision explained adequately how commission came to that conclusion, and there was no basis for appellate intervention — Utility companies appealed — Appeal dismissed — Regulatory framework allowed commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses but does not impose specific rate-setting methodology — Commission itself must decide upon specific test and methodology to employ — There is no obligation on commission to utilize particular prudence test methodology when reviewing costs on forecast basis — There is no presumption of prudence — Utility bears onus of proving that tariff it proposes is just and reasonable — Both methodology commission used, and application of that methodology, were reasonable given nature of costs.

Droit autochtone --- Divers

Compagnies réglementées ont demandé à ce que l'ensemble des coûts relatifs au régime de retraite soient inclus dans les exigences se rapportant à leur revenu — Compagnies ont fait valoir que les politiques applicables à leur régime de retraite étaient prudentes, établies de bonne foi par une tierce partie et conformes aux normes de l'industrie et qu'elles devraient être autorisées à inclure l'ensemble des coûts relatifs au régime de retraite dans leurs tarifs — Commission des services publics a refusé d'autoriser les compagnies à inclure certains coûts relatifs au régime de retraite dans leurs estimations des recettes nécessaires — Commission a conclu que la preuve ne permettait pas de conclure que le recouvrement à chaque année de l'ajustement annuel au coût de la vie (AACV) à raison de 100 p. cent de l'indice des prix à la consommation jusqu'à un maximum de 3 p. cent constituait une pratique courante reconnue — Compagnies ont interjeté appel — Appel a été rejeté — Cour d'appel a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable — Analyse en deux volets visant à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire — Au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux — Motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir — Compagnies ont formé un pourvoi — Pourvoi rejeté — Norme de contrôle applicable était celle de la décision raisonnable — Cadre réglementaire permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente, mais il n'imposait pas de méthodologie particulière pour l'établissement des tarifs — Il appartenait à la Commission de choisir quel test et quelle méthodologie employer — Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts — Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable — Méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

Droit public --- Services publics — Organismes de réglementation — Réglementation des tarifs

Compagnies réglementées ont demandé à ce que l'ensemble des coûts relatifs au régime de retraite soient inclus dans les exigences se rapportant à leur revenu — Compagnies ont fait valoir que les politiques applicables à leur régime de retraite étaient prudentes, établies de bonne foi par une tierce partie et conformes aux normes de l'industrie et qu'elles devraient être autorisées à inclure l'ensemble des coûts relatifs au régime de retraite dans leurs tarifs — Commission des services publics a refusé d'autoriser les compagnies à inclure certains coûts relatifs au régime de retraite dans leurs estimations des recettes nécessaires — Commission a conclu que la preuve ne permettait pas de conclure que le recouvrement à chaque année de l'ajustement annuel au coût de la vie (AACV) à raison de 100 p. cent de l'indice des prix à la consommation jusqu'à un maximum de 3 p. cent constituait une pratique courante reconnue — Compagnies ont interjeté appel — Appel a été rejeté — Cour d'appel a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable — Analyse en deux volets visant à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire — Au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux — Motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir — Compagnies ont formé un pourvoi — Pourvoi rejeté — Cadre réglementaire permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente, mais il n'imposait pas de méthodologie particulière pour l'établissement des tarifs — Il appartenait à la Commission de choisir quel test et quelle méthodologie employer — Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts — Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable — Méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

The Alberta Utilities Commission denied the request by a group of utility companies to recover through approved rates certain pension costs related to an annual cost of living adjustment (COLA). Instead of approving recovery for an adjustment of 100 per cent of annual consumer price index (CPI) up to a maximum COLA of 3 per cent, the Commission ruled that recovery of only 50 per cent of annual CPI was reasonable. The Alberta Court of Appeal dismissed the companies' appeal from the decision of the Commission and ruled that the analytical framework selected by the Commission was not unreasonable. A two-stage analysis of determining if expenditures were prudently incurred and then the setting of reasonable rates was not mandated and on the record, it was open to the Commission to determine that only 50 per cent of the COLA amounts should be included in the rates. The reasons for this decision explained adequately how the Commission came to that conclusion, and there was no basis for appellate intervention. The companies appealed.

Held: The appeal was dismissed.

Per Rothstein J. (McLachlin C.J.C., Abella, Cromwell, Moldaver, Karakatsanis and Gascon JJ. concurring): The applicable standard of review is reasonableness. The Commission was applying its expertise to set rates and approve payment amounts in accordance with the Electric Utilities Act and the Gas Utilities Act. The matter related to rate-making which is at the heart of a regulator's expertise and was deserving of a high degree of deference. The matter also turned on the Commission's interpretation of its home statutes, and a standard of reasonableness presumptively applied. The Alberta regulatory framework allows the Commission to set just and reasonable tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses. It does not impose a specific rate-setting methodology on the Commission. It falls to the Commission to decide upon the specific test and methodology to employ. There is no obligation on the Commission to utilize a particular prudence test methodology when reviewing costs on a forecast basis. There was no need for the Commission to employ a two-step process of first examining whether the decisions to incur costs were prudent. There was no need to apply a presumption of prudence in favour of the utility. The legislation contained the specific use of the word "prudent" to qualify the costs and expenses that electric and gas utilities are entitled to recover, but that did not mandate the use of the prudence test. It is the utility that bears the onus of proving that the tariff it proposes is just and reasonable. The methodology the Commission used, and the way it applied its methodology, were reasonable given the nature of the costs.

The Commission's interpretation and exercise of its rate-setting authority was reasonable. The disallowed costs were forecast costs. The utilities were not entitled to a no-hindsight prudence review. Under the reasonableness standard of review, the Commission's interpretation of its home statute was entitled to deference. The Commission did not expressly address the question of whether the statutory regime mandated a no-hindsight approach, but its decision to proceed without using a no-hindsight prudence test implied that it understood the relevant statutes not to mandate the utilities' desired methodology. A review of the relevant statutes showed that the Commission's approach was reasonable.

L'Alberta Utilities Commission a refusé la demande présentée par un groupe de compagnies oeuvrant dans le domaine du service public en vue de recouvrer, selon les taux approuvés, certaines charges de retraite correspondant à l'ajustement annuel au coût de la vie (AACV). Au lieu d'approuver ce recouvrement à raison de 100 p. cent de l'indice des prix à la consommation (IPC) de l'année (AACV d'au plus 3 p. cent), la Commission a jugé raisonnable le recouvrement de seulement 50 p. cent de l'IPC annuel. La Cour d'appel de l'Alberta a rejeté l'appel des compagnies interjeté à l'encontre de la décision de la Commission et a décidé que le cadre d'analyse utilisé par la Commission n'était pas déraisonnable. Une analyse en deux volets visant d'abord à déterminer si les dépenses avaient été prudemment encourues puis à établir des taux raisonnables n'était pas obligatoire et, au vu du dossier, il était loisible à la Commission de conclure que seulement 50 p. cent des montants relatifs à l'AACV devrait être inclus dans les taux. Les motifs de cette décision expliquaient adéquatement la manière dont la Commission en était venu à cette conclusion et la Cour d'appel n'était pas justifiée d'intervenir. Les compagnies ont formé un pourvoi.

Arrêt: Le pourvoi a été rejeté.

Rothstein, J. (McLachlin, J.C.C., Abella, Cromwell, Moldaver, Karakatsanis, Gascon, JJ., souscrivant à son opinion) : La norme de contrôle applicable était celle de la décision raisonnable. La Commission se fiait à son expertise pour établir les taux et approuver les paiements en conformité avec l'Electric Utilities Act et la Gas Utilities Act. La question se rapportait à la décision de fixer le taux, ce qui se situait au coeur de l'expertise de l'organisme de réglementation et commandait un haut degré de déférence. La question se rapportait également à l'interprétation par la Commission de sa propre loi et il fallait présumer que la norme de la décision raisonnable s'appliquait.

Le cadre réglementaire de l'Alberta permettait à la Commission d'établir des tarifs justes et raisonnables pour les fournisseurs d'électricité et de gaz qui voulaient obtenir le recouvrement de leurs coûts et dépenses encourus de manière prudente. Il n'imposait pas à la Commission une méthodologie particulière pour l'établissement des tarifs. Il appartenait à la Commission de choisir quel test et quelle méthodologie employer. La Commission n'était pas obligée d'utiliser une méthodologie particulière pour le test visant à déterminer la prudence lorsqu'elle révisait la prévision des coûts. Il n'était pas nécessaire que la Commission emploie une analyse en deux volets visant, en premier lieu, à déterminer si les décisions d'encourir les coûts étaient prudentes. Il n'était pas nécessaire de recourir à une présomption de prudence favorisant les fournisseurs. Le mot « prudent » était utilisé dans la législation pour qualifier les coûts et dépenses qu'un fournisseur d'électricité et de gaz pouvait recouvrer, mais cela ne rendait pas obligatoire l'usage du critère de prudence. Il revenait aux fournisseurs de démontrer que le tarif qu'ils proposaient était juste et raisonnable. La méthodologie utilisée par la Commission et la manière dont elle l'a appliquée étaient raisonnables compte tenu de la nature des coûts.

L'interprétation faite par la Commission et l'exercice de son pouvoir d'établissement des tarifs étaient raisonnables. Les coûts qui n'avaient pas été autorisés étaient des coûts prévus. Les fournisseurs n'avaient pas droit à un contrôle de la prudence excluant le recul. En vertu de la norme de la décision raisonnable, l'interprétation par la Commission de sa propre loi commandait de la déférence. La Commission n'a pas traité spécifiquement de la question de savoir si le régime statutaire rendait obligatoire une approche excluant le recul, mais sa décision d'aller de l'avant sans recourir à un critère de prudence excluant le recul indiquait implicitement qu'elle comprenait que les lois applicables ne rendaient pas obligatoire l'application de la méthodologie prônée par les fournisseurs. Une revue des lois applicables démontrait que l'approche de la Commission était raisonnable.

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Words and phrases considered:

just and reasonable rates

In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: [*Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 (S.C.C.) *OEB*], at para. 16. Consumers must pay what the Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": *OEB*, at para. 20.

prudence

Because, as will be discussed, the meaning of "prudence" is the focus of much of the debate in this case, it is helpful to start by examining the ordinary meaning of the word as a baseline for the subsequent analysis. Pertinent dictionary definitions give a range of meanings for "prudent", including "having or exercising sound judgement in practical affairs" (*The Oxford English Dictionary* (2nd ed. 1989), vol. XII, at p. 729), "acting with or showing care and thought for the future" (*Concise Oxford English Dictionary* (12th ed. 2011), at p. 1156), or "marked by wisdom or judiciousness [or] shrewd in the management of practical affairs" (*Merriam-Webster's Collegiate Dictionary* (11th ed. 2003), at p. 1002). While these definitions may vary in their nuance, the ordinary sense of the word is such that a prudent cost is one which may be described as wise or sound.

However, these dictionary definitions are not so consistent and exhaustive as to provide a complete answer to the question of the meaning of "prudent" costs in the context of the Alberta utilities regulation statutes. As such, a contextual reading of the statutory provisions at issue provides further guidance. In the context of utilities regulation, I do not find any difference between the ordinary meaning of a "prudent" cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost.

revenue requirement

The . . . Utilities submit that the Commission is bound to first assess costs put forward by a utility for prudence, and that prudently incurred costs must be approved for inclusion in the utility's "revenue requirement". This term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p.521.

Termes et locutions cités:

Prudence

Nous verrons plus loin que le débat porte en grande partie sur la signification de la notion de « prudence », si bien qu'il est utile d'examiner d'abord le sens ordinaire de ce terme comme point de référence pour l'analyse qui suivra. Les dictionnaires offrent une gamme de définitions de l'adjectif « prudent », dont les suivantes : [TRADUCTION] « qui a ou qui exerce un bon jugement dans les affaires d'ordre pratique » (*The Oxford English Dictionary* (2e éd. 1989), vol. XII, p. 729), [TRADUCTION] « qui agit en se souciant du lendemain ou qui manifeste un tel souci » (*Concise Oxford English*

Dictionary (12e éd. 2011), p. 1156), ou [TRADUCTION] « qui est empreint de sagesse ou de pertinence, [ou] qui est rompu à la gestion des affaires d'ordre pratique » (*Merriam-Webster's Collegiate Dictionary* (11e éd. 2003), p. 1002). Bien que ces définitions comportent des nuances, on peut en conclure, suivant le sens ordinaire de l'adjectif, qu'une dépense prudente est celle qui résulte d'une décision sage ou bonne.

Cependant, ces définitions ne sont pas suffisamment uniformes et exhaustives pour apporter une réponse définitive à la question de savoir ce qu'il faut entendre par des dépenses « prudentes » dans le contexte des lois qui réglementent les services publics en Alberta. Une interprétation contextuelle des dispositions législatives en cause offre donc un autre élément de réponse. Dans le contexte de la réglementation de services publics, je ne vois aucune différence entre des dépenses « prudentes » au sens ordinaire de ce terme et des dépenses que l'on pourrait qualifier de raisonnables. Ainsi, il ne serait pas imprudent de faire des dépenses raisonnables, pas plus qu'il ne serait prudent de faire des dépenses déraisonnables.

recette nécessaire

Les services publics ATCO soutiennent que la Commission doit d'abord se prononcer sur la prudence des dépenses invoquées par le service public et que les dépenses faites avec prudence doivent être approuvées aux fins de leur prise en compte dans les « recettes nécessaires » de l'entreprise. Ce poste s'entend des [TRADUCTION] « recettes dont l'entreprise a besoin au total pour le paiement de toutes ses dépenses susceptibles d'approbation et, également, pour recouvrer tous les coûts liés aux capitaux investis » (L. Reid et J. Todd, « New Developments in Rate Design for Electricity Distributors » dans G. Kaiser et B. Heggie, dir., *Energy Law and Policy* (2011), 519, p. 521).

tarification juste et raisonnable

En droit canadien, la tarification « juste et raisonnable » est celle qui est équitable tant pour le consommateur que pour le service public (*Northwestern Utilities Ltd. c. City of Edmonton*, [1929] S.C.R. 186, p. 192-193 (juge Lamont)). Selon un modèle fondé sur le coût du service, la tarification doit permettre à l'entreprise de recouvrer, à long terme, ses dépenses d'exploitation et son coût en capital. Grâce au recouvrement de ceux-ci, le service public peut continuer d'exercer ses activités et obtenir l'équivalent du coût du capital de manière à susciter l'investissement et à le maintenir. ([*Ontario (Commission de l'énergie) c. Ontario Power Generation Inc.*, 2015 CSC 44, (CÉO)], par. 16). Le consommateur doit payer ce que la Commission « prévoit qu'il en coûtera pour la prestation efficace du service » de sorte que, « globalement, il ne paie pas plus que ce qui est nécessaire pour obtenir le service » (CÉO, par. 20)

APPEAL from judgment reported at *ATCO Utilities, Re* (2013), 2013 ABCA 310, 2013 CarswellAlta 1984, 556 A.R. 376, 584 W.A.C. 376, 93 Alta. L.R. (5th) 234, 7 C.C.P.B. (2nd) 171 (Alta. C.A.).

POURVOI formé à l'encontre d'un jugement publié à *ATCO Utilities, Re* (2013), 2013 ABCA 310, 2013 CarswellAlta 1984, 556 A.R. 376, 584 W.A.C. 376, 93 Alta. L.R. (5th) 234, 7 C.C.P.B. (2nd) 171 (Alta. C.A.).

***Rothstein J.* (*McLachlin C.J.C, Abella, Cromwell, Moldaver, Karakatsanis, Gascon JJ.* concurring):**

1 In its decision of September 27, 2011, the Alberta Utilities Commission denied the request by ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (collectively the "ATCO Utilities") to recover, in approved rates, certain pension costs related to an annual cost of living adjustment ("COLA") for 2012. Instead of approving recovery for an adjustment of 100 percent of the annual consumer price index ("CPI") (up to a maximum COLA of 3 percent), the Commission ruled that recovery of only 50 percent of annual CPI (up to a maximum COLA of 3 percent) was reasonable. The Alberta Court of Appeal dismissed the ATCO Utilities' appeal from the decision of the Commission. The ATCO Utilities now appeal to this Court.

2 This matter was heard together with *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 (S.C.C.) ("*OEB*"), which also concerns the review of a rate-setting decision by a utilities regulator. Although the facts of the cases

are different, both involve issues of methodology, and, in particular, when — if ever — a regulator is required to apply a particular regulatory tool known as the "prudent investment test" in assessing a utility's costs.

3 The ATCO Utilities submit that the Commission is bound to first assess costs put forward by a utility for prudence, and that prudently incurred costs must be approved for inclusion in the utility's "revenue requirement". This term refers to "the total revenue that is required by the company to pay all of its allowable expenses and also to recover all costs associated with its invested capital": L. Reid and J. Todd, "New Developments in Rate Design for Electricity Distributors", in G. Kaiser and B. Heggie, eds., *Energy Law and Policy* (2011), 519, at p.521. The approved revenue requirement is then to be allocated to customers in the form of just and reasonable rates. The ATCO Utilities argue that the Commission failed to properly address the prudence of such costs. They say that in the absence of an explicit contrary finding, costs are presumed to be prudent. Further, the Utilities assert that prudence is to be established based on circumstances as of the date of the cost decision — not based on hindsight and the use of information not available to the utility when the decision to incur the cost was made.

4 The Office of the Utilities Consumer Advocate of Alberta argues that the Alberta regulatory framework does not impose a specific rate-setting methodology on the Commission; it falls to the Commission to decide upon the specific test and methodology to employ. Specifically, the Consumer Advocate argues that there is no obligation on the Commission to utilize a particular prudence test methodology when reviewing costs on a forecast basis. Nor is there a presumption of prudence. On the contrary, the onus is on the utility to demonstrate that the tariff it proposes is just and reasonable.

5 As in *OEB*, the relevant statutory framework does not impose upon the Commission the "prudence" methodology urged by the ATCO Utilities. Further, following the approach set out in *OEB*, the methodology adopted by the Commission and its application of this methodology were reasonable in view of the nature of the costs in question. I would dismiss the appeal.

I. Regulatory Framework

6 In Alberta, the Commission sets "just and reasonable" tariffs for electric and gas utilities seeking recovery of their prudent costs and expenses: s. 121(2)(a) of the *Electric Utilities Act*, S.A. 2003, c. E-5.1 ("*EUA*"); and s. 36(a) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("*GUA*").

7 In Canadian law, "just and reasonable" rates or tariffs are those that are fair to both consumers and the utility: *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.), at pp. 192-93, per Lamont J. Under a cost of service model, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs. Recovering these costs ensures that the utility can continue to operate and can earn its cost of capital in order to attract and retain investment in the utility: *OEB*, at para. 16. Consumers must pay what the Commission "expects it to cost to efficiently provide the services they receive" such that, "overall, they are paying no more than what is necessary for the service they receive": *OEB*, at para. 20.

II. Facts

A. The Pension Plan

8 Employees of the ATCO Utilities benefit from the Retirement Plan for Employees of Canadian Utilities Limited ("CUL", the parent company of the ATCO Utilities) and Participating Companies (the "Pension Plan"). The Pension Plan is administered by CUL, which is not itself regulated by the Commission. As the Pension Plan administrator, CUL acts in a fiduciary capacity in relation to Plan members and other Plan beneficiaries: s. 13(5) of the *Employment Pension Plans Act*, R.S.A. 2000, c. E-8. [1]

9 The Pension Plan includes a defined benefit plan (the "DB plan"), which was closed to new employees on January 1, 1997, and a defined contribution plan. The COLA applies only to the DB plan. The *Employment Pension Plans Act* requires that the DB plan be subject to actuarial calculations filed periodically with the Superintendent of Pensions for

Alberta: ss. 13 and 14;[2] and ss. 9 and 10 of the *Employment Pension Plans Regulation*, Alta. Reg. 35/2000.[3] Actuarial calculations determine, *inter alia*, the contributions that an employer must make to cover a DB plan's liabilities.

10 The assets of the CUL Pension Plan are pooled between all CUL member companies, regardless of whether they are regulated utility companies (like the ATCO Utilities) or not. The required employer funding is determined on an aggregate basis. If special payments must be made to address unfunded liabilities, the aggregate funding requirement is apportioned among the member entities of the Pension Plan.

11 No employer contributions to the Pension Plan were required between 1996 and the end of 2009 because the Pension Plan was in surplus position, and thus the ATCO Utilities did not have to include such contributions in their revenue requirement applications to the Commission. In the wake of the 2008 financial crisis, the market value of the Pension Plan's assets dropped and a large unfunded liability resulted, forcing the employers participating in the Pension Plan, including the ATCO Utilities, to resume making employer contributions in 2010.

B. The Pension Plan Funding Obligations

12 Section 48(3) of the *Employment Pension Plans Act*, (2000)[4] requires that the Pension Plan be funded in accordance with actuarial valuation reports. The actuarial valuation report relevant to this appeal (the "2009 Actuarial Report") was filed with the Superintendent of Pensions for Alberta on June 29, 2010 by Mercer (Canada) Limited, the Pension Plan's actuary. The report indicated that two types of payments were required. First, it determined the estimated payments required to address the projected benefits owed to beneficiaries for 2010, 2011 and 2012. These are also called "current service costs". Second, it determined that the DB plan had an unfunded liability of $157.1 million across all CUL entities, requiring all the employers participating in the Pension Plan, including the ATCO Utilities, to make minimum annual special payments in the aggregate amount of $16.4 million until December 31, 2024 to address the liability. The ATCO Utilities alone were liable for approximately $13.9 million of the annual aggregate special payment amount.

13 The cost of living adjustment issues in this case involve both the contributions that the ATCO Utilities must make into the DB plan and the benefits paid to retirees out of the plan. With regard to the ATCO Utilities' contributions into the plan, the 2009 Actuarial Report included a provision for "post retirement pension increases" that is based on the DB plan's COLA formula and the actuarial report's assumption for inflation. This provision affects the payments that the ATCO Utilities are required to make into the DB plan for the three-year period covered by the report. In this case, this increase was 2.25 percent per year for all three years.

14 With regard to the payment of benefits to retirees under the DB plan, the ATCO Utilities' parent company CUL sets the COLA annually. Sections 6.9(a) and 6.12(a) of the DB plan prescribe that CUL determines the COLA by taking into consideration annual percentage changes in the Consumer Price Index for Canada and any previous adjustments paid. These provisions cap the adjustment set by CUL at 3 percent per annum.

III. Decisions Below

A. Alberta Utilities Commission: ATCO Utilities, Re (2010), 84 C.C.P.B. 89 (Alta. U.C.) (the "Decision 2010-189")

15 On July 10, 2009, the ATCO Utilities filed an application with the Commission to determine, *inter alia*, the amount of employer pension contributions that would be included in their revenue requirements in 2010. The ATCO Utilities' proposed contributions reflected a COLA set at 100 percent of annual Canada CPI (up to a maximum of 3 percent), as CUL had used for a number of years. However, in the Commission's view, setting COLA at 100 percent of CPI year after year was not required by the wording of the Pension Plan. It concluded "that ratepayers should not bear any incremental pension funding costs" that arise from CUL's practice of setting COLA "where it [was] demonstrated that such incremental costs prove to be unreasonable or imprudent in the circumstances": para. 118.

16 However, the Commission did not find the evidence filed in this application to be sufficient to draw conclusions with respect to whether the COLA was prudent. As a result, it did not reduce the COLA of 100 percent of annual CPI (up to a maximum of 3 percent) for the ATCO Utilities' 2010 revenue requirements. Nonetheless, the Commission stated that it "would like to investigate the possibility of adjusting COLA as a mechanism in prudently managing utility pension expense" for the years 2011 onward: para. 123. It directed the ATCO Utilities to prepare a 2011 pension common matters application to address issues related to COLA and CUL's discretion in setting COLA.

B. Alberta Utilities Commission: 2011 CarswellAlta 1646 (Alta. U.C.) (WL Can.) (the "Decision 2011-391")

17 On December 15, 2010, the ATCO Utilities filed a pension common matters application pursuant to the Commission's direction in *Decision 2010-189*. The Commission published its *Decision 2011-391* on September 27, 2011. It is this decision that is the subject of appeal in this Court.

18 In reviewing the COLA included in the ATCO Utilities' revenue requirement application, the Commission wrote that the reasonableness of setting it at 100 percent of CPI had to be evaluated "in the circumstances applicable at the time that ATCO Utilities apply to include pension expense in revenue requirement": *Decision 2011-391*, at para. 87. The significant unfunded liability of the Pension Plan was such a circumstance. The Commission was of the view that the DB plan permitted CUL to exercise its discretion in setting the COLA, and that this discretion was "an available tool" for CUL to actively manage the DB plan unfunded liability as it carried out its fiduciary and contractual obligations: para. 83. "[T]he availability of that discretion and the exercise, or lack thereof, of that discretion [was] a relevant and material consideration" in determining whether the ATCO Utilities' pension expenses were reasonable and should be included in revenue requirements: para. 83.

19 The Commission found that the ATCO Utilities' practice of awarding an annual COLA of 100 percent of CPI every year was not "an acceptable standard practice", in light of benchmark evidence showing a wider range of COLA percentages used by defined benefit pension plans among other entities in a comparator group: *Decision 2011-391*, at para 87. The majority of the entities set COLA between 50 percent and 75 percent of CPI. The Commission also found that a reduction in COLA would not undermine the Utilities' ability to attract new employees, nor would it encourage current employees to leave.

20 The Commission concluded that the COLA included in current service costs to be recovered through tariffs after January 1, 2012 and until the next actuarial valuation should be 50 percent of the annual Canada CPI, to a maximum of 3 percent. The ATCO Utilities' revenue requirements for 2012 were to be reduced accordingly.

21 However, with regard to the special payments addressing the unfunded liability for 2012, the Commission stated that it would not require that the ATCO Utilities file an updated actuarial report reflecting a lower COLA and that it would only begin disallowing a COLA of 100 percent with regard to special payment costs from 2013 onward. This decision resulted from the Commission's conclusion that filing a new actuarial report "would be costly, and consume an undue amount of company, intervener and Commission resources given the time remaining in 2011 to complete a new report and file it for approval with the Commission and subsequently with the Superintendent of Pensions", especially as a new report would be filed by January 1, 2013 as it stood: *Decision 2011-391*, at para. 99. The Commission did not reduce special payments to be recovered in 2012 because it was not "in the best interest of ATCO Utilities, ratepayers or pensioners to implement a change to the COLA calculation [at this time] given the uncertain pension funding impacts that may result from a new actuarial valuation and report": para. 100. Reductions in liability as a result of a reduction of COLA would be captured in ongoing special payments set for 2013 onward.

C. Alberta Utilities Commission: ATCO Utilities, Re (2012), 97 C.C.P.B. 298 (Alta. U.C.) (the "Decision 2012-077")

22 On November 2, 2011, the ATCO Utilities filed a review and variance application of *Decision 2011-391*. The ATCO Utilities requested that the Commission vacate its direction to reduce the amount of COLA to 50 percent of CPI for regulatory purposes.

23 The Commission found that the arguments raised by the ATCO Utilities did not give rise to a substantial doubt as to the correctness of *Decision 2011-391* and denied the ATCO Utilities' request for review and variance.

D. Alberta Court of Appeal: 2013 ABCA 310, 93 Alta. L.R. (5th) 234 (Alta. C.A.)

24 The Alberta Court of Appeal granted leave to appeal *Decision 2011-391*. Conducting a reasonableness review, the court held it was open to the Commission to reduce the ATCO Utilities' revenue requirements to reflect a COLA of 50 percent of CPI. The Court of Appeal dismissed the Utilities' appeal.

IV. Issues

25 This appeal raises three issues:

1. What is the standard of review?

2. Does the regulatory framework prescribe a certain methodology in assessing whether costs are prudent?

3. Was it reasonable for the Commission to refuse to incorporate 100 percent of CPI to a maximum of 3 percent into the ATCO Utilities' COLA revenue requirements?

V. Analysis

A. Standard of Review

26 The standard of review of the Commission's decision in applying its expertise to set rates and approve payment amounts in accordance with the *Electric Utilities Act* and the *Gas Utilities Act* is reasonableness: *OEB*, at para. 73; see *New Brunswick (Board of Management) v. Dunsmuir*, 2008 SCC 9, [2008] 1 S.C.R. 190 (S.C.C.), at paras. 53-54.

27 Nonetheless, the ATCO Utilities argue that the jurisprudence favours applying a standard of correctness. However, the cases they cite — *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (S.C.C.) ("*Stores Block*"), *AltaLink Management Ltd., Re*, 2012 ABCA 378, 539 A.R. 315 (Alta. C.A.), and *ATCO Gas & Pipelines Ltd. v. Alberta (Utilities Commission)*, 2009 ABCA 246, 464 A.R. 275 (Alta. C.A.) — are not analogous to the matter at hand. They each were said to involve "true questions of jurisdiction", where the regulator was called on to determine whether it had the statutory authority to decide a particular question. This Court's recent jurisprudence has emphasized that true questions of jurisdiction, if they exist as a category at all, an issue yet unresolved by the Court, are rare and exceptional: *A.T.A. v. Alberta (Information & Privacy Commissioner)*, 2011 SCC 61, [2011] 3 S.C.R. 654 (S.C.C.), at para. 34. In any event, this case involves ratemaking. As Bastarache J. noted in *Stores Block*, ratemaking is at the heart of a regulator's expertise and is therefore deserving of a high degree of deference: para. 30.

28 To the extent that an appeal also turns on the Commission's interpretation of its home statutes, a standard of reasonableness also presumptively applies: *A.T.A.*, at para. 30. The presumption is not rebutted in this case.

B. Methodology for Determining Costs and Just and Reasonable Rates Under the Electric Utilities Act and the Gas Utilities Act

29 The application by the ATCO Utilities, one of which is an electric utility and the other a gas utility, involves both the *EUA* and the *GUA*. Both statutes direct the Commission to set just and reasonable rates. The *EUA* requires the Commission to "have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover" various "prudent" or "prudently incurred" costs: s. 122; see also s. 102. A gas utility, on the other hand, is "entitled to recover in its tariffs" costs that the Commission determines to be "prudent": s. 4(3) of the *Roles, Relationships and Responsibilities Regulation*, Alta. Reg. 186/2003 ("*RRR Regulation*"); see also s. 36 *GUA*.

30 The ATCO Utilities argue that the guarantee of a reasonable opportunity to recover their costs requires that the Commission must first examine whether the decisions to incur costs were prudent and must apply a presumption of prudence in favour of the utility. Unless these costs are found not to be prudent, they are to be included in the utility's revenue requirement. The ATCO Utilities say that in conducting its prudence inquiry, the Commission is required to use the prudence test as described by the Ontario Court of Appeal in *Hydro One Networks Inc., Re*, 2013 ONCA 359, 116 O.R. (3d) 793 (Ont. C.A.), which is the subject of the companion appeal to this case. In that case, the Ontario Court of Appeal relied on a formulation of prudence review set out in *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)* (2006), 210 O.A.C. 4 (Ont. C.A.), at para. 10:

> • Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
>
> • To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
>
> • Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
>
> • Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time. [para.16]

31 The ATCO Utilities argue that the statutes' express use of the word "prudent" to qualify the costs and expenses that electric and gas utilities are entitled to recover necessarily mandates the use of that prudence test. I will refer to it as the "no-hindsight" test.

32 The language of the relevant provisions of the *EUA* and *GUA* differs from the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B, in the companion *OEB* appeal. While the *EUA* and the *GUA* contain specific references to "prudence", the *Ontario Energy Board Act, 1998* does not. Further, regulations passed under the *Ontario Energy Board Act, 1998* expressly permit the Ontario Energy Board to establish a methodology to determine whether revenue requirements are just and reasonable. The *EUA* and *GUA* do not include a direct grant of methodological discretion. However, like the statutory scheme in *OEB*, neither the *EUA* nor the *GUA* impose a specific methodology [5] and, as will be explained, their references to "prudence" do not impose upon the Commission the specific methodology advanced by the ATCO Utilities.

(1) Prudence Under the EUA

33 The question before this Court is whether the Commission's interpretation and exercise of its rate-setting authority was reasonable. The ATCO Utilities argue that the statutory framework supports its assertion that it was entitled to a no-hindsight prudence review. Under the reasonableness standard of review, the Commission's interpretation of its home statute is entitled to deference. In this case, the Commission did not expressly address the question of whether the statutory regime mandated a no-hindsight approach. Rather, its decision to proceed without using a no-hindsight prudence test implies that it understood the relevant statutes not to mandate the ATCO Utilities' desired methodology. It is thus necessary to examine the terms of the relevant statutes to determine whether the Commission's approach was reasonable. In doing so, this Court may make use of the traditional tools of statutory interpretation with the goal of determining whether the Commission's approach was reasonable: see *British Columbia (Securities Commission) v. McLean*, 2013 SCC 67, [2013] 3 S.C.R. 895 (S.C.C.), at paras. 37-41.

34 The words of a statute are to be interpreted "in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament": *Rizzo & Rizzo Shoes Ltd., Re*, [1998] 1 S.C.R. 27 (S.C.C.), at para. 21, quoting E. A. Driedger, *Construction of Statutes* (2nd ed. 1983), at p. 87. Because, as will be discussed, the meaning of "prudence" is the focus of much of the debate in this

case, it is helpful to start by examining the ordinary meaning of the word as a baseline for the subsequent analysis. Pertinent dictionary definitions give a range of meanings for "prudent", including "having or exercising sound judgement in practical affairs" (*The Oxford English Dictionary* (2nd ed. 1989), vol. XII, at p. 729), "acting with or showing care and thought for the future" (*Concise Oxford English Dictionary* (12th ed. 2011), at p. 1156), or "marked by wisdom or judiciousness [or] shrewd in the management of practical affairs" (*Merriam-Webster's Collegiate Dictionary* (11th ed. 2003), at p. 1002). While these definitions may vary in their nuance, the ordinary sense of the word is such that a prudent cost is one which may be described as wise or sound.

35 However, these dictionary definitions are not so consistent and exhaustive as to provide a complete answer to the question of the meaning of "prudent" costs in the context of the Alberta utilities regulation statutes. As such, a contextual reading of the statutory provisions at issue provides further guidance. In the context of utilities regulation, I do not find any difference between the ordinary meaning of a "prudent" cost and a cost that could be said to be reasonable. It would not be imprudent to incur a reasonable cost, nor would it be prudent to incur an unreasonable cost.

36 The *EUA* provides that an "owner of an electric distribution system must prepare a distribution tariff for the purpose of recovering the *prudent* costs of providing electric distribution service by means of [its] electric distribution system": s. 102(1). To receive approval for the distribution tariff, the owner must apply to the Commission: s. 102(2) *EUA*. When considering a tariff application, the Commission must ensure, *inter alia*, that the tariff is "just and reasonable" (s. 121(2)(a) *EUA*), a requirement for which the burden of proof "is on the person seeking approval of the tariff" (s. 121(4) *EUA*).

37 Section 122 of the *EUA* provides that the Commission "must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover" a series of eight types of costs and expenses:

> a) the costs and expenses associated with capital related to the owner's investment in the electric utility, ...
>
> . . . . .
>
> if the costs and expenses are *prudent*...
>
> b) other *prudent costs and expenses* associated with isolated generating units, transmission, exchange or distribution of electricity ... if, in the Commission's opinion, they are applicable to the electric utility,
>
> c) amounts that the owner is required to pay under this Act or the regulations,
>
> d) the costs and expenses applicable to the electric utility that arise out of obligations incurred before the coming into force of this section and that were approved by the Public Utilities Board, the Alberta Energy and Utilities Board or other utilities' regulatory authorities if, in the Commission's opinion, the costs and expenses continue to be *reasonable and prudently incurred*,
>
> e) its *prudent costs and expenses* of complying with the Commission rules respecting load settlement,
>
> f) its prudent costs and expenses respecting the management of legal liability,
>
> g) the costs and expenses associated with financial arrangements to manage financial risk associated with the pool price if the arrangements are, in the Commission's opinion, prudently made, and
>
> h) any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities.

38 Section 122 refers to prudence in two different ways. Most frequently, the adjective "prudent" qualifies the expression "costs and expenses", which indicates that a utility enjoys a reasonable opportunity to recover costs and expenses that are prudent. Absent a definition of the word "prudent" or a clear inference that it refers to a no-hindsight rule as described in *Enbridge*, this prudence requirement is to be understood in the sense of the ordinary meaning of the word: for the

listed costs and expenses to warrant a reasonable opportunity of recovery, they must be wise or sound; in other words, they must be reasonable.

39 By contrast, certain provisions use the adverb "prudently" to qualify the utility's decision to incur costs: s. 122(1)(d) speaks of costs and expenses that are "reasonable and prudently incurred" and s. 122(1)(g) refers to costs and expenses associated with financial arrangements that were "prudently made". Though this case does not call upon this Court to evaluate the types of expenses covered by s. 122(1)(d) or (g), statutory language referring to "prudently incurred" costs appears to speak more directly to a utility's decision to incur costs at the time the decision was made. Such language may more directly implicate the no-hindsight approach urged by the ATCO Utilities in this case than language that merely speaks of "prudent costs". This issue is further complicated for costs arising under s. 122(1)(d), where costs must both "continue to be reasonable *and* prudently incurred". The proper interpretation of these provisions is a question best left for a case in which the issue arises.

40 In their submissions, the ATCO Utilities do not parse the different contexts in which the word "prudent" is used in s. 122. They argue more generally that the references to "prudence" imply that a no-hindsight test is required, and that a utility's costs must be presumed to be prudent.

41 However, the different uses of "prudence" in s. 122 are instructive. If the statute requires the Commission to approve "prudently incurred" expenses, it may be unreasonable for the Commission to fail to apply a no-hindsight methodology in reviewing such expenses. However, the costs at issue in this case do not fall within the categories of costs for which the statute grants recovery of "prudently incurred" costs. The use of the adjective "prudent" to qualify "costs and expenses" elsewhere in s. 122 does not itself imply a specific methodology. Nothing in the ordinary meaning of the word "prudent" or the use of this word in the statute as a stand-alone condition says anything about the time at which prudence must be evaluated.

42 Further, s. 121(4) of the *EUA* provides that the burden of establishing that the proposed tariffs are just and reasonable falls on the public utility. The requirement that tariffs be just and reasonable is a foundational requirement of the tariff-setting provisions of the *EUA*. Tariffs will not be just and reasonable if they do not comply with the statutory requirement of s. 122 that the costs and expenses be prudent. Thus, contrary to the ATCO Utilities' proposed methodology, the utilities' burden to establish that tariffs are just and reasonable necessarily imposes on the utilities the burden of establishing that costs are prudent.

43 In sum, neither the ordinary meaning of "prudent" nor the statutory language indicate that the Commission is bound by the *EUA* to apply a no-hindsight approach to the costs at issue, nor is a presumption of prudence statutorily imposed in these circumstances.

(2) Prudence Under the GUA

44 The *GUA* requires, *inter alia*, that on application by the owner of a gas utility, the Commission "fix just and reasonable" rates that "shall be imposed, observed and followed afterwards by the owner of the gas utility": s. 36(a). Section 44(1) provides that changes in rates must be approved by the Commission, and the "burden of proof to show that the increases, changes or alterations are just and reasonable is on the owner of the gas utility seeking to make them": s. 44(3). Further, s. 4(3) of the *RRR Regulation* provides that

> [a] gas distributor is entitled to recover in its tariffs the prudent costs as determined by the Commission that are incurred by the gas distributor ....

45 While the *RRR Regulation* makes a specific reference to the recovery of "prudent" costs, I do not read this prudence requirement as implying a presumption of prudence and application of a no-hindsight rule. Regarding the "no hindsight" element, the statutory provisions do not use "prudent" to describe the decision to incur the costs, but rather to describe the costs themselves. Although s. 4(3) of the *RRR Regulation* uses the term "incurred", it is used to indicate that the provision applies to costs incurred by the utility. No temporal inference can be drawn from the use of "incurred" in this

context; it is not used in a manner that calls for examination of the prudence of the decision to incur certain costs. The inquiry under s. 4(3) of the *RRR Regulation* rather asks whether the costs themselves can be said to be "prudent". The *GUA* does not include a requirement that a no-hindsight rule must apply in assessing whether costs are prudent, nor does the text of the *GUA* or the *RRR Regulation* imply such a rule. Regarding a presumption of prudence, s. 44(3) of the *GUA* stipulates that the utility has the burden to establish that the rates are just and reasonable. Like the *EUA*, this in turn places the burden of establishing the prudence of costs on the utility.

(3) Conclusion With Respect to Statutory Requirements of the EUA and GUA

46 Though the statutes do contain language allowing for the recovery of "prudent" costs, the *EUA* and the *GUA* do not explicitly impose an obligation on the Commission to conduct its analysis using a particular methodology any time the word "prudent" is used. Further, reserving any opinion on whether the term "prudently incurred" might require a particular no-hindsight methodology, in this particular case the bare use of the word "prudent" does not, on its own, mandate a particular methodology.

47 It is thus apparent that the relevant statutes may reasonably be interpreted not to impose the ATCO Utilities' asserted prudence methodology on the Commission. The existence of a reasonable interpretation that supports the Commission's implied understanding of its discretion is enough for the Commission's decision to pass muster under reasonableness review: *McLean*, at paras. 40-41. Thus, the Commission is free to apply its expertise to determine whether costs are prudent (in the ordinary sense of whether they are reasonable), and it has the discretion to consider a variety of analytical tools and evidence in making that determination so long as the ultimate rates that it sets are just and reasonable to both consumers and the utility.

C. Characterization of the Costs at Issue: Forecast or Committed

48 As explained in *OEB*, understanding whether the costs are committed or forecast may be helpful in reviewing the reasonableness of a regulator's choice of methodology: see para. 83. Committed costs are those costs that a utility has already spent or that were committed as a result of a binding agreement or other legal obligation that leaves the utility with no discretion as to whether to make the payment in the future: para. 82. If the costs are forecast, there is no reason to apply a no-hindsight prudence test because the utility retains discretion whether to incur the costs: para. 83. By contrast, the no-hindsight prudence test may be appropriate when the regulator reviews utility costs that are committed: paras. 102-05.

49 Determining whether particular costs are committed or forecast turns on factual evidence relevant to those costs as well as on legal obligations that may govern them. Factual evidence may take the form of details regarding the structure of the utility's business, relevant conduct on the part of the utility, and the factual context in which the costs arise. Legal issues may relate to any contractual, fiduciary or regulatory obligations that grant or bar discretion on the part of the utility in incurring the costs at issue. Where the regulator has made an assessment of whether the costs are committed or forecast, that assessment is owed deference by this Court.

50 On the basis of the evidence and the arguments before it, the Commission found that the "COLA amount ha[d] not yet been awarded for 2012 because consideration of the COLA adjustment occurs towards the end of the calendar year": *Decision 2011-391*, at para. 93. The Commission concluded that there was enough time from the date *Decision 2011-391* was published on September 27, 2011 to the end of the calendar year for the ATCO Utilities and their parent CUL "to prospectively decide whether to separately fund any difference CUL may choose to pay beyond the COLA level approved for regulatory purposes for 2012 onwards": para. 93. This finding supports a characterization of the disallowed COLA costs as forecast because their disallowance left it open to CUL to reduce the COLA that would apply to the 2012 benefit payments to 50 percent of CPI or to incur the COLA of 100 percent of CPI regardless, knowing that the differential would ultimately be borne by the utilities: *OEB*, at para. 82.

51 However, the Commission did not disallow the use of a COLA of 100% of CPI (up to a maximum of 3 percent) with regard to the special payments intended to address the unfunded liability and fixed by the 2009 Actuarial Report for the year 2012. The Commission did so by reasoning that any consumer overpayment that resulted in 2012 would be compensated through reduced special payments once a new report was prepared for 2013 onward.

52 In their factum in this Court, the ATCO Utilities submitted that the COLA costs were committed in the same way as the costs fixed by binding collective agreements were in the companion *OEB* appeal. In oral argument, counsel for the ATCO Utilities explained that the pension actuary prepares an actuarial report at intervals of a maximum of three years and files it with the Superintendent of Pensions: see ss. 13 and 14 of the *Employment Pension Plans Act* (2000) [6] and ss. 9 and 10 of the *Employment Pension Plans Regulation*, (2000). [7]

53 In this case, the 2009 Actuarial Report applied for the years 2010, 2011 and 2012. The pension actuary determined the employer's required contribution to fund projected benefits owed to beneficiaries and to address any unfunded liability in the DB plan. For each of the three years covered by the report, the actuary assumed a post retirement pension increase of 2.25 percent per year to be included in required contributions [8] . It was argued by the ATCO Utilities that the employer is required by law to make such contributions: s. 48(3) of the *Employment Pension Plans Regulation* (2000) [9] . Accordingly, the ATCO Utilities submitted that once the actuarial report covering 2010, 2011 and 2012 had been filed, the amounts identified in that valuation, including a post retirement pension increase of 2.25 percent, should be understood as committed.

54 To address this argument, a distinction must be drawn between the COLA that is used to determine the post retirement pension increases applied to employer contributions paid into the DB plan, and the COLA applied to benefit payments paid out of the plan. While the ATCO Utilities were legally bound to make contributions including a post retirement pension increase of 2.25 percent into the plan for 2012, the actual COLA paid out to beneficiaries was set by CUL on an annual basis. The ATCO Utilities' information responses to the Commission in preparation for their 2011 pension common matters application show that the actual COLA set by CUL for 2010 was 0 percent and for 2011 was 1.7 percent.

55 The ATCO Utilities' argument that the costs are committed rests on the notion that if the Commission reduces the recoverable COLA to 50 percent of CPI (up to a maximum of 3 percent), they risk incurring a shortfall because the COLA recovered through rates will be less than the post retirement pension increases of 2.25 percent that they were legally obliged to contribute.

56 However, while both the employer contributions into the DB plan and the benefit payments made to beneficiaries are subject to cost of living adjustments, the portion of *Decision 2011-391* at issue in this appeal was concerned specifically with the reasonableness of the COLA to be set by CUL for the 2012 benefit payments. As such, the Commission's disallowance was with respect to the COLA benefits to be paid out to beneficiaries in 2012 — not to the employer contributions into the DB plan.

57 Contrary to the submissions of the ATCO Utilities, the facts of this case are different from those in *OEB*. In *OEB*, the utility was bound to pay certain costs by virtue of collective agreements with separate counterparties, the employee unions. In this case, the Commission found that the COLA applied to benefit payments from the DB plan was set by the ATCO Utilities' parent, CUL, and that CUL retained discretion over the setting of the COLA for the test period. DB plan members would ultimately receive benefits reflecting a COLA of 100 percent in 2012 only if CUL decided to set the COLA at that level.

58 CUL may have exercised that discretion in such a way as to avoid saddling its regulated subsidiary with costs it knew would not be recovered. Accordingly, while the ATCO Utilities were required to make contributions reflecting a post retirement pension increase of 2.25 percent into the DB plan pursuant to the 2009 Actuarial Report, the COLA

applied to benefit payments for 2012 was not committed when the Commission issued its *Decision 2011-391*. This is so because at the time *Decision 2011-391* was published, CUL had yet to set COLA for 2012.

59 It was not unreasonable for the Commission to decide, without applying a no-hindsight analysis, that 50 percent of CPI (up to a maximum of 3 percent) "represent[ed] a reasonable level for setting the COLA amount for the purposes of determining the pension cost amounts for regulatory purposes" in 2012: *Decision 2011-391*, at para. 92.

D. Considering the Impact on Rates in Evaluating Costs

60 The ATCO Utilities argue that in considering the prudence of the COLA costs the Commission was preoccupied with the aim of reducing rates charged to customers.

61 As discussed above, a key principle in Canadian regulatory law is that a regulated utility must have the opportunity to recover its operating and capital costs through rates: *OEB*, at para. 16. This requirement is reflected in the *EUA* and *GUA*, as these statutes refer to a reasonable opportunity to recover costs and expenses so long as they are prudent. A regulator must determine whether a utility's costs warrant recovery on the basis of their reasonableness — or, under the *EUA* and *GUA*, their "prudence". Where costs are determined to be prudent, the regulator must allow the utility the opportunity to recover them through rates. The impact of increased rates on consumers cannot be used as a basis to disallow recovery of such costs. [10] This is not to say that the Commission is not required to consider consumer interests. These interests are accounted for in rate regulation by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service. In other words, the regulatory body ensures that consumers only pay for what is reasonably necessary: *OEB*, at para. 20.

62 In this case, the Commission did emphasize the effect that reducing the COLA would have on the ATCO Utilities' unfunded liability. It is also true that a lower unfunded liability based on an actuarial report using a 50 percent COLA instead of 100 percent would mean a lower revenue requirement, and thus lower rates passed on to consumers. However, I do not agree with the ATCO Utilities' submission that the Commission, in considering the effect of COLA on the utilities' unfunded pension liability, was basing its disallowance on concerns about rate hikes for consumers. Regulators may not justify a disallowance of prudent costs solely because they would lead to higher rates for consumers. But that does not mean a regulator cannot give any consideration to the magnitude of a particular cost in considering whether the amount of that cost is prudent.

63 Indeed, it seems axiomatic that any time a regulator disallows a cost, that decision will be based on a conclusion that the cost is greater than ought to be permitted, which leads to the inference that consumers would be paying too much if the cost were incorporated into rates. But that is not the same as disallowing a cost *solely* because it would increase rates for consumers. In this case, the Commission found it unreasonable for the ATCO Utilities to receive payments to cover a COLA of 100 percent while they carried a large unfunded liability on their books, in part because of evidence from comparator companies that COLA figures of less than 100 percent were common, and because of the Commission's finding that a COLA of 100 percent was not necessary to ensure that the ATCO Utilities could attract and retain employees. While this conclusion carries with it the consequence that rates will be lower as a result, the Commission reasoned from the prudence of the costs themselves, not from a desire to keep rates down, to arrive at its conclusion to disallow costs. I find nothing unreasonable in the Commission's reasoning in this regard.

VI. Conclusion

64 The Commission was not statutorily bound to apply a particular methodology to the costs at issue in this case. The use of the word "prudent" in the *EUA* and *GUA* cannot by itself be read to impose upon the Commission the specific no-hindsight methodology urged by the ATCO Utilities.

65 While there are undoubtedly situations in which a failure to apply a no-hindsight methodology may result in unjust outcomes for utilities, and thus violate the statutory requirement that rates must strike a just and reasonable balance

between consumer and utility interests, the Commission did not act unreasonably in this case. The disallowed costs were forecast costs. Accordingly, it was reasonable in this case for the Commission to evaluate the ATCO Utilities' proposed revenue requirement in light of all relevant circumstances. Further, because the Commission did not use impermissible methodology, it was not unreasonable for the Commission to direct the ATCO Utilities to reduce their pension costs incorporated into revenue requirements by restricting annual COLA to 50 percent of CPI (up to a maximum of 3 percent) for current service costs from 2012 onward and for special payments addressing the unfunded liability from 2013 onward.

66 For these reasons, I would dismiss the appeal.

Appeal dismissed.

Pourvoi rejeté.

Footnotes

1 This provision has since been replaced by s. 35(2) of the *Employment Pension Plans Act*, S.A. 2012, c. E-8.1.

2 These provisions have since been replaced by s. 13 of the *Employment Pension Plans Act*, (2012).

3 These provisions have since been replaced by ss. 48 and 49 of the *Employment Pension Plans Regulation*, Alta. Reg. 154/2014.

4 This provision has since been replaced by s. 52(2)(b) of the *Employment Pension Plans Act* (2012).

5 The *GUA* does provide some methodological guidance to the Commission with regard to calculating a utility's return on its rate base by specifying what information may be considered in this process: "In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Commission shall give due consideration to all facts that in its opinion are relevant"; (s. 37(3)). However, it does not provide any further methodological guidance for assessing the recoverability of a utility's costs.

6 These provisions have since been replaced by s. 13 of the *Employment Pension Plans Act* (2012).

7 These provisions have since been replaced by ss. 48 and 49 of the *Employment Pension Plans Regulation* (2014).

8 For clarity, the 2009 Actuarial Report and the DB plan use two separate terms to describe annual pension benefit increases, though they are conceptually linked: the DB plan refers to cost of living adjustment (or COLA), while the 2009 Actuarial Report refers to "post retirement pension increases". The 2009 Actuarial Report's post retirement pension increase figure of 2.25 percent was based on the DB plan's formula for COLA and the actuarial report's assumption for inflation.

9 This provision has since been replaced by ss. 60(2)(b) and 60(3) of the *Employment Pension Plans Regulation* (2014).

10 Regulators may, however, take into account the impact of rates on consumers in deciding *how* a utility is to recover its costs. Sudden and significant increases in rates may, for example, justify a regulator in phasing in rate increases to avoid "rate shock", provided the utility is compensated for the economic impact of deferring its recovery: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.), at para. 43.

TAB 24

MANITOBA	**Board Order 7/03**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**February 3, 2003**

Before: G. D. Forrest, Chair
R. A. Mayer, Q.C., Vice Chair
Dr. K. Avery Kinew, Member

A FILING BY MANITOBA HYDRO TO PROVIDE AN INFORMATION UPDATE REGARDING FINANCIAL RESULTS, FORECASTS, METHODOLOGIES, PROCESSES, AND OTHER MATTERS RELATING TO SALES RATES CHARGED BY MANITOBA HYDRO

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Executive Summary

The Manitoba Hydro-Electric Board ("Hydro") filed a status update with The Public Utilities Board ("the Board") on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board determined that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition may have a significant impact on the future overall operations of Hydro.

Hydro believes holding rates constant is a more prudent course of action than offering rate reductions because of the robust export markets and favourable water conditions, which underpinned Hydro's strong financial performance, may not continue at present levels. Rates at or near their current levels will assist Hydro in achieving its longer term financial objectives. Hydro also stated domestic rates are less than market prices in nearby interconnected markets. Current rates are, on average, the lowest of any utility in North America. Lower rates may encourage more domestic consumption, which would reduce revenues as profitable export sales are foregone. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

During the course of the public hearing, the Board examined a number of specific areas related to Hydro's operations including operating results and financial projections, financial targets and risk, capital expenditures, extra provincial revenues, payments to the Province of Manitoba, operating, administrative and finance expenses, transmission tariffs, load forecasts and overall revenue requirements. As a result of this review, the Board identified a number of areas of concern, and made a number of recommendations including:

- Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and focus on reducing long-term debt.
- Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba.
- Hydro continue to monitor and control operating and administrative expenses.
- Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy.

In addition to the above recommendations, the Board directed Hydro to:

- File an updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;
- File a detailed debt management strategy;
- Undertake a study to quantify specific reserve provisions required to cover major risks and contingencies;
- Undertake a study on the merits of implementing an inverted rate structure for all customer classes;

- Undertake a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;
- Undertake a study which considers time of use rates for General Service classes based on a seasonal, weekly, daily, and hourly basis;
- Identify and specifically account for all export-related capital expenditures in its capital forecasts to ensure that export revenues are appropriately matched against the full cost of production;
- Undertake a study on the methods and impacts with respect to the classification of generation costs in the Cost of Service Study;
- Re-examine the current level of Demand Side Management programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board;
- Consider the use of wind power in remote diesel electric communities and file a report with the Board; and

A considerable amount of time at the hearing was directed towards a review of the various cost of service studies filed by Hydro, and in particular, the proposed changes in methodology from the methodologies previously approved by the Board. The most contentious issue, and the issue with the greatest impact on cost of service results, is the allocation of net export revenues between customer classes. In this Order, the Board has not accepted Hydro's proposed cost of service methodology. The Board has directed Hydro to file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflects a number of specific directives as set out in the Order including the cost treatment of export classes.

Although Hydro is not seeking any change to firm rates currently charged to customers, the Board noted that certain customer classes have consistently paid rates higher than their allocated costs. Therefore, the Board has directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 that reflects:

(a) A 1% rate decrease for General Service Small customers;

(b) A 2% rate decrease for General Service Large ("GSL") customers greater than 30 kV; and

(c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

The Board understands that this change will likely bring the General Service Medium class and the GSL <30 kV class closer to unity. Therefore, no further rate adjustment will be ordered for this class.

Given that uniform rates have provided recent rate decreases to some residential customers and the residential class revenue to cost coverage ratio has been consistently below unity (i.e., subsidized by other classes), no further rate changes are ordered for the residential rate class at this time.

The Board also directed Hydro to file a separate application for approval of an open access transmission tariff by no later than June 30, 2003.

The Board approved the Curtailable Rate Program, confirmed as final a number of interim ex parte Orders, and approved extending the Limited Use Billing Demand Rate option to March 31, 2004.

The Board also directed Hydro to establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings even if no rate changes are required. This timeframe will improve the efficiency, effectiveness and timeliness of the regulatory process.

Subject to these and other specific rate directives contained in this Order, the Board has confirmed Hydro's remaining existing rate schedules to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

(b) Net export revenues are allocated on the basis of generation and transmission costs only in accordance with Order 51/96.

(c) Transmission costs, including Dorsey, are classified as 100% demand.

(d) Transmission and ancillary services costs are allocated on the basis of the 2 CP.

(e) Generation demand costs are allocated on the basis of the 2 CP.

(f) Energy related costs of generation are allocated on the basis of class annual energy (Non-Coincident Peak).

(g) HVDC costs (other than Dorsey) are functionalized as generation.

(h) Only transmission facilities recognized for inclusion in Hydro's Transmission Tariff are included in the transmission function.

(i) The creation of a Firm Export Class. This class should include long-term firm export sales and one-year firm export sales, with costs allocated on a fully embedded basis using a 2 CP allocation as employed for general service customers; and

(j) The creation of an Opportunity Export Class. This class should allocate costs using a similar basis to the domestic interruptible GSL customer class.

21.12 Rate Design

21.12.1 General

Although Hydro did not apply for any changes in rate design, the Board and the Intervenors considered the issues of rate design to be of considerable importance in this status update filing. As part of the Board's review as to whether the rates charged remain just and reasonable, the Board not only examined the overall revenue requirement, but also the cost of service methodology, and the rate structure itself.

The Board is disappointed with the inaction of Hydro to comply with the spirit of Order 51/96 with regard to undertaking a study and reporting to the Board by no later than the next GRA to develop a comprehensive rate design policy. More than six years have elapsed since that directive was issued, and Hydro stated at this hearing that it has no intention of preparing such a study in the near future. Such inaction is a disservice to the many Hydro customers, particularly those who might benefit from such a comprehensive rate design policy.

Having reviewed rate design issues as part of this status update, the Board believes that certain rates require adjustment.

21.12.2 Rates

After examining the overall revenue requirement of Hydro, the Board finds that there is no need for an overall rate adjustment for all customer classes. However, the Board is of the view that rates for certain customer classes should be adjusted.

Much time was spent at the hearing reviewing the Cost of Service Study. A revenue to cost ratio of 1.0 indicates that costs allocated to a customer class equal the revenues earned from that customer class. While unity may be the desired goal, Order 51/96 sets a zone of reasonableness target at 0.95 to 1.05 for revenue to cost coverage ratios. The Board is of the view that this zone of reasonableness of 0.95 to 1.05 continues to be an appropriate target for rate setting purposes.

As demonstrated in the table in Section 17.8.5, certain customer classes and subclasses have consistently remained outside of this zone of reasonableness for long periods of time, in some cases more than 10 years. Therefore, the Board is convinced that directional rate adjustments are appropriate now to address these inequities. Accordingly, the Board will order a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in subclasses greater than 30 kV. Such rate decreases are to be effective April 1, 2003. The Board will direct Hydro to file new rate schedules for Board approval reflecting these rate adjustments.

The Board will also eliminate the winter ratchet over the next two years, which will reduce revenues to Hydro by approximately $3 to 4 million. The Board understands that this change will likely bring the GSM class and GSL subclass less than 30 kV closer to unity. Therefore, no further rate adjustment will be ordered for the GSM or GSL less than 30 kV subclass at this time.

The Board is confident that these rate adjustments will not impact the overall financial strength of Hydro, or its ability to achieve its financial targets.

21.12.3 Inverted Rates and Rate Structure

The declining block structure is largely the result of the historical circumstances of electrification throughout the Province and the construction of major generating plants on the Northern rivers. While the Board is not prepared at this time to support an inverted rate structure, the Board accepts that certain concepts of an inverted rate structure for residential customers may have merit for consideration in the future. The Board compliments both Mr. Lazar and Hydro for preparing thoughtful evidence on this matter and raising interesting new approaches. The Board believes that more study is required before an inverted rate structure can be considered for any customer class. The Board will direct Hydro to prepare a study on the merits of an inverted rate structure across all rate classes including transition and implementation issues. As part of this study, Hydro should evaluate the impact of an inverted rate structure on electric heat customers and residential customers with higher than average loads. This study should be filed with the Board by no later than December 31, 2003.

While the issue of inverted rates was largely confined to residential rates, the Board investigated demand and energy charges levied on larger General Service customers as part of the overall rate design. In the Board's opinion, some of Hydro's demand charges are in the mid to high range as compared to other jurisdictions in Canada, while the energy charges are amongst the lowest in Canada.

The Board is of the belief a lower demand charge and higher energy charge may serve as an impetus to further conservation of electricity since the users may become more aware of their consumption and hence, may attempt to minimize usage. Accordingly, the Board will direct Hydro to prepare a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge and include recommendations and a timetable for possible implementation. The study should be filed with the Board by no later than December 31, 2003.

21.12.4 Winter Ratchet and Limited Use Billing Demand

In the 1996 GRA, Hydro sought to eliminate the winter ratchet with the implementation of seasonal rates. However, with little actual evidence and no customer consultation, the Board did not support the implementation of seasonal rates, and directed further study by Hydro. Since then, the LUBD program was introduced to alleviate some irritants posed by the winter ratchet. The Board is of the view that winter ratchet continues to pose problems for customers unable to benefit from the LUBD program.

The traditional rationale for the winter ratchet is that additional winter capacity to meet peak demand requires significant and costly capital expansions. The winter ratchet is designed to recover capacity costs incurred to meet this peak demand. The current system load runs nearly at capacity throughout the year as any additional capacity beyond domestic use is sold on the export market. Therefore, the Board finds that the use of the winter ratchet is not valid in the current circumstances. Accordingly, the Board will order Hydro to phase out the winter ratchet in two steps. On April 1, 2003, the winter ratchet is to be decreased to 70% of the maximum previous winter demand measured in December 2002, and January and February 2003. On April 1, 2004, the winter ratchet is to be eliminated. The Board will order Hydro to file the resulting rate schedules, for Board approval, prior to the above dates.

The Board will order the LUBD be eliminated on April 1, 2004. All LUBD customers will then revert to the billing rate of their appropriate class. Until April 1, 2004 the LUBD rate option will be considered a temporary rate offering. The Board also expects Hydro to inform all LUBD customers of this decision and its implication. The Board will grant final approval of Order 118/02 which extended the LUBD rate option on an interim ex parte basis.

21.12.5 Time of Use Rates

In Order 51/96 the Board directed Hydro to prepare a comprehensive rate policy including time of use rates which remains outstanding. The Board heard testimony that Hydro continues to install specialized metering equipment for certain general service customers with time of use capability. Accordingly, the Board considers it important to proceed with the development of time of use rates and directs Hydro to prepare a study, including a timetable and a plan for implementation, for a time of use rate program. Such study should also consider time of use rates for general service classes based on a seasonal, weekly, daily and hourly basis, including an evaluation of each alternative. The study should be filed with the Board by no later than December 31, 2003.

21.12.6 Diesel Rates

Any determination of whether rates are just and reasonable must include an examination of rates charged to those customers serviced by Hydro's diesel generation. The Board cannot make a determination on which customer should be included in a specific rate class of government versus non-government or whether a customer has sufficient resources to pay the bill, or funding formulas are appropriate.

During the hearing, Hydro stated it would be filing a separate application for diesel rates in December 2002. Such an application has now been filed and the Board will consider diesel rate issues at a future public hearing to review this filing.

21.12.7 Curtailable Rates

Hydro applied for a new CRP which included only minor variations from the existing curtailable service program. The rationale for curtailments has changed and, as stated by Hydro witnesses, the number of curtailments will likely decrease sharply. However, the Board is reasonably satisfied with the rationale used in the calculation of the Reference Discount.

TAB 25

DECISION

NSUARB-NSPI-P-892
NSPI-P-202
2011 NSUARB 184

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE *PUBLIC UTILITIES ACT*

- and -

IN THE MATTER OF AN APPLICATION by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

- and -

IN THE MATTER OF AN APPLICATION by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited for Approval of amendments to Nova Scotia Power Incorporated's Load Retention Tariff and for a Load Retention Rate effective January 1, 2012

BEFORE:
Peter W. Gurnham, Q.C., Chair
Roland A. Deveau, Q.C., Acting Vice-Chair
Kulvinder S. Dhillon, P. Eng., Member

COUNSEL:

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BOWATER MERSEY PAPER COMPANY LIMITED
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MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
Al Dominie

PROGRESSIVE CONSERVATIVE CAUCUS OFFICE
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Jennifer Edge
Sarah Reeves

PROVINCE OF NOVA SCOTIA (Departments of Energy, Environment and Natural Resources)
Stephen T. McGrath, LL.B.
Ryan Brothers, LL.B.

HEARING DATES: September 19, 21, 22 and October 24 - 27, 2011

UNDERTAKINGS: November 4, 2011

FINAL SUBMISSIONS: November 15, 2011

BOARD COUNSEL: S. Bruce Outhouse, Q.C.

LIST OF INTERVENORS: Appendix A

DECISION DATE: **November 29, 2011**

DECISION: **Settlement Agreement approved; Average rate increase of 5.6% effective January 1, 2012. Load Retention Rate, as applied for, denied. Load Retention Rate, as amended by the Board, approved.**

TABLE OF CONTENTS

1.0 INTRODUCTION

[1] This Decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the "Board") on September 19, 21, 22 and October 24 - 27, 2011, in the matter of an application by Nova Scotia Power Incorporated ("NSPI", the "Company", the "Utility"), dated May 13, 2011, for approval of revisions to its Rates, Charges and Regulations (the "NSPI Application") and an application dated June 22, 2011, by NewPage Port Hawkesbury Corp. ("NewPage") and Bowater Mersey Paper Company Limited ("Bowater") (collectively known as "NPB") for amendments to the Load Retention Tariff ("LRT") and a Load Retention Rate ("LRR") (the "NPB Application").

[2] NSPI is engaged in the production and supply of electrical energy. It distributes electricity through a province-wide system and, as at December 31, 2010, served approximately 489,000 customers, including six municipal electric utilities.

[3] In its Application, NSPI requested an increase in rates in order to meet its estimated revenue requirement increase for 2012 of $94.4 Million. NSPI used 2012 estimated costs as a 'test year' for the purpose of determining the additional revenue it required and the corresponding rate increases for its various customer classes, should its Application be approved. The proposed overall average rate increase was 7.3%, with certain customer classes subject to a higher or lower rate increase. The average residential customer would see a 7.1% increase with increases ranging from 5.5% to 13.5% for all other metered classes of customers.

[4] The NPB Application requested amendments to the terms and conditions of NSPI's existing LRT. These proposed revisions would extend the applicability of this LRT to instances where there is an impending business closure due to the economic

distress of NSPI's largest customers (i.e., NewPage and/or Bowater). Further, NPB proposed a new pricing mechanism that would result in a new LRR. The new rate is proposed to be in effect for five years, up to and including 2016.

[5] If approved, the proposed LRR would result in a further increase to electricity rates for NSPI's other customer classes. For example, if both applications of NSPI and NPB were approved by the Board, the average residential customer would see a 9.4% increase (compared to a proposed 7.1% increase under NSPI's application). For all other metered classes of customers, the increases would range from 8.4% to 9.6% if the applications of both NSPI and NPB are approved.

[6] The Board determined that both applications would be heard concurrently and that the Intervenors in NSPI's Application would be recognized as Intervenors in NPB's Application.

[7] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows:

> **Approval of schedule of rates and charges of utility**
> **64 (1)** No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.
>
> **Filing with Board**
> **(2)** The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act. R.S., c. 380, s. 64.
>
> **Notice of hearing of application for rate changes**
> **86** Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board. R.S., c. 380, s. 86.

[8] A total of 20 formal Intervenors responded to the applications of NSPI and NPB. A number of these parties were represented at the hearing by counsel. The Nova Scotia Department of Energy, Department of Environment, and Department of Natural Resources (the "Province"); the Small Business Advocate ("SBA"); the Consumer Advocate ("CA"); Avon Group ("Avon"), whose counsel represented 14 Intervenors; NPB; Halifax Regional Municipality ("HRM"); the Liberal Caucus Office; the Progressive Conservative Caucus Office; and the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's Application and both opposing and supporting NPB's Application.

[9] On August 22, 2011, NSPI's largest customer, NewPage, announced an indefinite shut down of its Port Hawkesbury operations. In early September, NewPage filed and obtained creditor protection under the federal *Companies' Creditors and Arrangement Act*. NewPage's parent company, NewPage Corporation, and certain of its other U.S. based subsidiaries, have filed for bankruptcy protection in the U.S. under Chapter 11 of the *United States Bankruptcy Code*. During the public hearing, the Board was advised of a Court approved process to find a purchaser for the NewPage plant in Port Hawkesbury.

2.0 BACKGROUND

[10] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The Board regulates NSPI in the public

interest on a cost of service basis. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental ratemaking principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>   (a) in the control of the total amounts of service supplied by the company;
>   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
>
> [Board Decision, March 31, 2005, p. 14]

[11] The Board continues to make its decisions in accordance with the *Act*, and the principles noted above.

[12] At the commencement of the public hearing on September 19, 2011, NSPI notified the Board it had reached a Settlement Agreement (the "GRA Agreement") on most of the outstanding issues in the NSPI Application. The GRA Agreement was

supported by most of the Formal Intervenors. The Board adjourned the hearing to provide an opportunity to all parties to file an executed copy of the GRA Agreement with the Board. The hearing reconvened on September 21, 2011, at which point NSPI witnesses explained the terms of the GRA Agreement and testified with respect to the outstanding issues.

3.0 SETTLEMENT AGREEMENT

3.1 The Board's approach to settlement agreements

[13] In its Decision dated November 5, 2008, the Board outlined its general approach to settlement agreements submitted to it for approval:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.
>
> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.
>
> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.

> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [Board Decision, 2008 NSUARB 140]

3.2 The GRA Agreement in the present case

[14] The GRA Agreement addresses most outstanding issues between NSPI and its customers, with the exception of cost of service issues and points related to the rates which apply to large customers under the Large Industrial Rate and the ELI 2P-RTP.

[15] Moreover, the GRA Agreement contains a deferral mechanism related to the recovery of non-fuel costs (net of non-fuel variable O&M costs) by NSPI in the event NewPage and/or Bowater shut down their operations indefinitely in 2012 (or remain closed in the case of NewPage). In that event, the GRA Agreement provides that NSPI will recover its non-fuel costs (net of non-fuel variable O&M costs) from the other customer classes starting in 2013. It should be noted that if either or both of NewPage and Bowater are off the system, variable fuel costs related to their load are avoided.

[16] The GRA Agreement reads as follows:

> 2012 GRA Settlement Agreement
>
> **Load**
>
> 1. The original GRA 2012 load forecast filed on May 13 will be used to calculate 2012 general rates. This is without prejudice to future determination about what timing of load forecast is the appropriate load for rate-setting purposes when the mid-year load forecast is available in a GRA year. The Parties agree that the mid-year load forecast will be used for FAM and DSM purposes as usual.
> 2. Due to the indefinite shut down and creditor protection of New Page Port Hawkesbury, load for this customer may not materialize in 2012 at the CBL level included in rates. The future of Bowater Mersey Paper Company is also uncertain, in light of the evidence in the Load Retention Tariff (LRT) application. Setting rates that include revenue from NPB will not provide the utility the opportunity to recover its costs and would therefore not be just and reasonable. Therefore, in order to maintain the lowest reasonable rate increase by setting rates to include NPB load, the parties agree that:

a. The NPB load will be based upon the levels forecast in the May 13 filing, and the forecasted non-fuel contribution from these customers will be calculated as the forecast total revenue from all load of these customers less the forecast BCF revenue for these customers.

b. Any amount of unrecovered NPB contribution to non-fuel costs net of non-fuel variable O&M costs, will be deferred for later recovery from all customers beginning in 2013. Non-fuel variable costs are deemed to be $500,000 annually for the entire NPB load. The non-fuel cost amount will be determined by deducting actual 2012 NPB fixed cost recovery from the forecasted amount of 2012 NPB fixed cost recovery as forecast at the time of setting 2012 rates. The amount will incorporate a reduction for non-fuel variable O&M costs that is proportionate to the actual total load for NPB. The forecast amount of 2012 fixed cost recovery will be quantified as part of the NSPI 2012 GRA Compliance Filing, on which all parties will have the right to comment.

c. The parties agree that NPB should provide security for the payment of their account, and parties will support a request to the UARB by NSPI for such security.

Fuel and Purchased Power Forecast

3. The Base Cost of Fuel in general rates will be based upon the May 13 filing (amount that includes NPPH load). Due to uncertainty about 2012 load, the FAM incentive will be suspended (i.e., will not operate) in 2012.
4. NSPI will adopt the Liberty recommendations relating to the forecast cost of imports, without adopting the approach as an established new methodology. The approach will be reviewed with the FAM SWG for potential revision of the FAM Plan of Administration. NSPI estimates this change will reduce the fuel forecast by $1.7M + 3.1M. The increase in the fuel forecast for 2012 will therefore be $31.3M ($36.1M - 4.8M).
5. This agreement does not affect the 2011 FAM processes, which will operate as usual to establish recovery of the 2011 AA, and the BA (including the 2010 Fuel Deferral amount), as well as reflect the earlier stakeholder agreement to return $14.5M to customers relating to the 2010 earnings deferral. The 2012 FAM process will recover the remaining BA portion of the 2010 Fuel Deferral amount.
6. Other issues related to fuel raised by Intervenors are open for consideration during the upcoming FAM processes.

Return on Equity/Capital Structure

7. Treatment as follows:

a. Capital Structure – rates will be set on 37.5% equity, NSPI may use a maximum actual equity of 40%, actual average equity will be used to calculate return on equity results.

b. ROE – rates will be set on 9.20% ROE, with a target earnings range of 9.1 to 9.5%; a corresponding adjustment will be made to the s.21 AAA mechanism.

c. This reduces revenue requirement from the application by $7.5M.

OM&G

8. For the purpose of the 2012 revenue requirement and without prejudice to future positions, incentives for Executives of NSPI will be paid by shareholders and therefore removed from 2012 customer rates – reduces revenue requirement by $250,000.
9. Pension – NSPI's pension costs are accepted in rates.

10. Salary/wage increase assumption – adopt the result, but not the methodology, of Liberty's recommendation (reduction in revenue requirement of $470K).
11. Succession planning – reduce amount by $1M to $4M. No further review required. This incorporates Meyer recommendation relating to FTEs not yet in workforce.
12. Capitalization rates – NSPI will update during compliance to reflect any changes that are consequential from adjustments to capital items in rate base, otherwise no change from NSPI proposal.
13. Sustainability – recover costs as proposed. No further review required.
14. Vegetation Management and Storms – withdraw increases relating to Vegetation Management and Storm costs (reduction in revenue requirement of $7.1M).
15. Insurance – reduce requested increase by $1M.
16. DSM amortization – as proposed by NSPI in filing.
17. Digby Wind – reduce OM&G by $300,000 as proposed by NSPI and Ramas.
18. Total OM&G revenue requirement reduction of $10.1M.

Rate Base

19. FAM Deferral amount – no change from NSPI filing (consultant proposal would have increased revenue requirement)
20. Reductions to rate base:
    a. Remove Co-Fired biomass and Bag House projects from capital plan (and remove offsetting AFUDC/AO/Depreciation). Reduces revenue requirement by $1.9M.
    b. Adopt Liberty proposed adjustment to rate base relating to pension costs ($9.9M reduction to rate base, $0.7M reduction in revenue requirement).
    c. CWC – maintain as presently in rates using "black box" approach, without prejudice to parties' right to make future arguments – no adoption of changes to methodology. Reduces rate base by $26.9M, reduces revenue requirement by $1.9M.
    d. Further rate base reduction, at NSPI's discretion, sufficient to reduce revenue requirement by $1.0M.
    e. No other rate base adjustments from NSPI application as filed.
    f Total effect on revenue requirement of these changes - $5.5M reduction

COSS and non-revenue requirement

21. Streetlights – rates will be as proposed by NSPI subject to the following adjustments:
    a. Parties agree that LEDs will be used for all replacements effective immediately and until UARB approval of the new capital program. The cost of these interim change-outs will be capitalized and parties will support any U&U application that may be necessary to obtain UARB approval of this interim program.
    b. Interim rate will be the rate as proposed in NSPI's May 13 filing subject to two changes:
        i. Fixture capital cost will be reduced by 15% from NSPI's original proposal. This reduction in the fixture capital cost will also apply to the January 1, 2012 rates.
        ii. No conversion fees will be charged until the 2012 LED Streetlight rates are in effect.
    c. The proposed realignment of rates with costs of the unmetered services of electricity and fixture capital will be introduced in two phases beginning in January 2012. NSPI will submit at the time of 2012 Compliance Filing a set of

streetlight rates that will be effective January 1, 2012 that incorporate 50% (in terms of cost impact) of the methodological adjustments. The complete change will be made in the next General Rate Application.

d. Without prejudice to a later determination of the value of stranded assets, the parties agree that for the purposes of calculating the 2012 conversion fee, the format in NSPI's Appendix G, Schedule 10 will be used with a year-ending 2011 Net Plant Value of $12 million for rate-making purposes to be recovered over 10 years, rather than $23 million predicated on a 5 year recovery period as is the case under NSPI's Application. As well, the schedule will be amended to include forecast retirements and depreciation over the 10 year period. If the program timeline remains 5 years at the time of final UARB approval of the capital work order for LED Streetlights, parties acknowledge this value for stranded assets is not anticipated to be accurate.

e. NSPI is entitled to full recovery of its prudently incurred non-LED street light asset costs. At future General Rate Applications, pricing of the energy and capital components of streetlight rates (LED, non-LED and conversion fees) will reflect NSPI's actual experience. NSPI will monitor the recovery of its stranded costs and is entitled to seek regulatory approval of changes to streetlight rates and conversion fees to ensure that all of its costs are recovered.

22. COSS issues:

    a. Adopt NSPI's corrections to the COSS and Mel Whalen evidence that accepts six adjustments to the COSS and proposes changing the energy classification of all projects that have an environmental component to include only investments made to meet environmental objectives which are a function of energy.

    b. All other COSS changes will be withdrawn. Certain Intervenors may take the position that Terms of Reference should be set leading to a COSS hearing in the near future.

23. Revenue to Cost ratios – may be litigated by Intervenors.

24. Large Industrial Tariff changes – NSPI grandfathering proposal to be adopted.

25. ELI 2P-RTP Tariff changes – may be litigated by Intervenors.

26. Subject to necessary adjustments to incorporate paragraph 7 above, the s.21 AAA Mechanism will continue to operate on a go forward basis until the s.21 amount is fully paid. Amounts in excess of both the range of return on equity and in excess of the room available in the s.21 AAA Mechanism will be returned to customers.

27. This settlement is for the GRA 2012 application only and is without prejudice to any of the parties freshly addressing any of the issues in a future GRA application.

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Summary of Total Adjustments – 2012 Revenue Requirement

	Adjustment	Revenue Requirement	Average Rate Increase (GRA Table 10.8)
May 13 Application		$94.4M increase	7.2%
Fuel and Purchased Power	($4.8M)		
ROE	($7.5M)		
OMG	($10.1M)		
Rate Base	($5.5M)		
Total Adjustments	($27.9M)	($27.9M)	
Total Change in Revenue Requirement		$66.5M Fuel - $31.3M Non-Fuel – $35.2	5.06% 2.38% 2.68

[Exhibit N-49]

[17] In his Opening Statement at the hearing, Rob Bennett, NSPI's CEO, stated that the negotiated GRA Agreement represents a consensus which balances all interests:

> The agreement we're presenting today clearly demonstrates that we can bring all the varied customer interests together to reach consensus for the common good. Doing so should always get us to a better result than an adversarial hearing process. No one loses in a negotiated settlement: everyone's interests are balanced and addressed.
>
> [Exhibit N-52, p. 2]

[18] He concluded:

> The agreement we are presenting today won't solve all our longer term challenges, but it's a step in the right direction. Like all settlements, it is a balance of competing interests. It addresses the reality of the rising costs in our business, while keeping the rate impact on customers as low as possible. It is a fair and prudent agreement.
>
> [Exhibit N-52, p. 4]

[19] In NSPI's Closing Submission, counsel for the Company reiterated that the GRA Agreement advances the public interest:

> NSPI submits the Settlement Agreement in this 2012 General Rate Application is balanced and fair to customers as well as to the Company. The public interest will be advanced by the implementation of the Settlement Agreement and the elements contained within the Agreement, including the new electricity rates on January 1, 2012.
>
> [NSPI Closing Submission, p. 3]

13.1 Findings

[262] The objective of having informed consumers is a worthwhile goal. However, the Board considers that the decision of how to inform ratepayers about the impact of government regulations and programs is a policy decision to be made by the Province.

[263] In the circumstances, the Board makes no direction in this respect.

14.0 COMPLIANCE FILING

[264] NSPI is directed to file a Compliance Filing no later than December 9, 2011.

[265] The Formal Intervenors must provide comments, if any, no later than December 16, 2011.

15.0 SUMMARY OF BOARD FINDINGS

Settlement Agreement

[266] The Board approves the GRA Agreement, which represents a comprehensive resolution of most contested issues between NSPI and the Intervenors. It addresses a number of important elements raised in the NSPI Application.

[267] It reduces NSPI's revenue requirement by $27.9 Million from the original requested increase of $94.4 Million. The resulting increase to the revenue requirement is $66.5 Million ($31.3 Million for fuel and $35.2 Million for non-fuel).

[268] In its Application, NSPI requested that its current return on equity of 9.35% be increased to 9.6% (within a range of 9.35 to 9.85%). Under the terms of the GRA Agreement, the return on equity is reduced to 9.2% (within a range of 9.1% to 9.5%).

This reduces the revenue requirement by $7.5 Million. Other costs are reduced as noted in this Decision.

Cost of Service

[269] The Board agrees with the majority of the Intervenors that there is merit to review the current cost of service. The evidence presented notes that some of the assumptions and principles used in the COSS such as the current generation mix (including renewables) and emission control requirements need a review.

[270] The Board's current 2012 Regulatory Schedule does not allow enough time for a review of the COSS. Therefore, the Board orders that NSPI plan for a COSS hearing in 2013.

Revenue to Cost Ratios

[271] A change to the R/C ratio band of 95% – 105% is denied.

[272] The Board recognizes the issue of the Small General and General Demand classes being on the high end of the R/C ratio band. The SBA has recommended that the R/C ratio for the Small General and General Demand classes be lowered to 1.03 from 1.05.

[273] The Board agrees with the SBA's recommendation to lower the R/C ratio for these two customer classes to 1.03 for this Decision and NSPI is ordered to include this change in the Compliance Filing.

ELI 2P-RTP Rate

[274] At the time the ELI 2P-RTP rate (which currently serves Bowater and NewPage) was approved, the Board noted it was innovative and new to NSPI and that there may be a need for the Board to review the terms and conditions once experience was gained under the rate.

[275] The Board ordered an annual review. The reason for the annual review was so that the Board could carefully monitor experience under the rate to ensure that neither NSPI nor other customers were being disadvantaged. The Board also observes that the rate was ordered prior to the institution of the FAM which has added some complications.

[276] The Board approves the changes to the rate as recommended by NSPI.

[277] The Board is persuaded that these changes are necessary and prudent at this stage of the life of the rate. The reporting currently in place should continue.

[278] To avoid rate shock to the ELI 2P-RTP rate customers, the Board finds that the increase should be limited to 150% of the average of the other classes. The Board finds scenario #2 suggested by Mr. Whalen, Board Counsel's consultant, is the appropriate mechanism to do this and directs NSPI to take this into account in the Compliance Filing.

[279] The rate increases by customer class ordered in this Decision are estimated to be as follows:

	Rate Increase %
Residential	6.1
Sm Gen	2.5
Gen	2.8
Lg Gen	5.7
Sm Ind	5.6
Med Ind	7.5
Lg Ind	7.5
ELI 2P-RTP	8.5
Muni	7.4
Unmetered	-3.4

[280] The average rate increase is approximately 5.6%.

Load Retention Rate

[281] The Board concludes that it has jurisdiction under the *Public Utilities Act* to consider the application for a LRT based on the economic distress of extra large industrial customers.

[282] Load retention tariffs are utilized in circumstances where providing the discounted tariff benefits not only the customers qualifying for the tariff but also the other customers on the system.

[283] The test that the Board has applied in this case is whether, on a balance of probabilities, the other customers of NSPI would be better off by having NPB remain on the system (on the load retention rate) than those customers would be if NPB stopped taking service. The test is satisfied if the load retention rate fully recovers avoided costs of supplying NPB and makes a positive contribution to the fixed and common costs of NSPI. The Board will not, and indeed cannot, approve a rate in circumstances where the other customers are worse off (because they are subsidizing NPB) than they would be if these customers left the system.

[284] The Board is not satisfied, on a balance of probabilities, that the LRR as applied for by NPB will recover avoided costs and make a positive contribution to fixed and common costs over the five year term. It has reached this conclusion for the following reasons:

- The Board concludes that a five year term is simply not supported by the preponderance of evidence. The likelihood is that the actual costs will be higher than the five year levelized costs calculated in the NPB Application.
- The Board agrees with the Intervenors that the $2.00 adder, combined with the five year term, does not provide a reasonable likelihood that the LRR will recover avoided costs and make a contribution to fixed costs.
- The Board is very concerned about the five year LRR structure as proposed, which provides NPB a significant advantage in the early years and escalates rapidly in years 3, 4 and 5 to rates in excess of what the mills now say they can afford to pay.

[285] The Board, in the circumstances, could simply dismiss the NPB Application. However, that would not contribute to meeting the financial challenge that the two mills face, nor would it provide other customers at least some opportunity to receive a contribution to NSPI's system costs from the continued operation of the two mills.

[286] In an attempt to find a solution that both meets the legal test and goes part way to meeting NPB's requirements, the Board is prepared to approve an amended LRR which has as its foundation recovery of NSPI's year-by-year estimate of avoided

costs, as identified in Appendix C of Dr. Rosenberg's Pre-Filed Evidence, plus an adder. The term would be three years and the variable incremental cost would be the annual avoided cost in Appendix C in 2013 and 2014. In 2012, the Board would substitute $56.24, as taken from Undertaking U-9 filed by Mr. Whalen, which is based on rate case estimates.

[287] The Board concludes that a LRR which uses the incremental costs as described above, is limited to a three year term, and has a $4.00 adder, would be appropriate. The Board reserves the right to adjust the LRR if actual costs vary significantly from LRR assumptions. Accordingly, the rate would be as follows:

Year	Variable Incremental Rate ($/MWh)	+ Adder	Total Energy Charge
2012	$56.24	$4.00	$60.24
2013	$61.77	$4.00	$65.77
2014	$63.86	$4.00	$67.86

This provides some measure of rate stability for NPB. Further, LRR customers will pay DSM and FAM riders in 2012.

[288] The Board is satisfied, on a balance of probabilities, that other customers will be better off under this amended LRR design with NPB on the system than if they leave. This is because the term is shorter – three years; the rate is based on annual variable incremental costs; there is a reasonable adder; and there is a re-opener if actual costs vary significantly from the rate assumptions.

Deferral and Undertaking to Manage Costs

[289] The GRA Agreement and this Decision defer the impact of any loss of load from NewPage or Bowater to 2013. Mr. Bennett has confirmed NSPI's undertaking

to take all prudent and reasonable steps to minimize costs to other ratepayers if the NPB load, or a portion of it, remains off the system.

[290] The Board has determined that a review of the deferral amount will occur in 2012 as part of a 2013 general rate application. In the event there is no general rate application in 2012 for 2013, the review will occur during the FAM proceeding in late 2012 and the deferral will be added to the issues list.

[291] Whether the review of the deferral amount occurs in the context of the general rate application or the FAM proceeding, the Board and Intervenors will be able to question NSPI on whether it has taken all prudent and reasonable steps to minimize costs to other ratepayers if the NPB load, or a portion of it, remains off the system. If the actions taken by NSPI are deemed insufficient or imprudent by the Board, it will order accordingly.

[292] An Order will issue following the Compliance Filing.

DATED at Halifax, Nova Scotia, this 29th day of November, 2011.

Peter W. Gurnham

Roland A. Deveau

Kulvinder S. Dhillon

Document: 196889

APPENDIX A

NOVA SCOTIA POWER INC.
2012 RATE APPLICATION P-892

- and -

NEWPAGE PORT HAWKESBURY CORP. and BOWATER MERSEY PAPER COMPANY LIMITED
LOAD RETENTION RATE APPLICATION P-202

COMBINED LIST OF INTERVENORS

Avon Group
(Avon Valley Greenhouses Ltd.)
(Canadian Salt Company Limited)
(CFK Inc.)
(Crown Fibre Tube Inc.)
(Halifax Grain Elevator Limited)
(High Liner Foods Incorporated)
(Imperial Oil Limited)
(Lafarge Canada Inc.)
(Maritime Paper Products Ltd.)
(Michelin North America (Canada) Inc.)
(Minas Basin Pulp & Power Company Ltd.)
(Oxford Frozen Foods Limited)
(Sifto Canada Corp.)
(Nustar Terminals Canada Partnership)

Cape Breton Explorations Ltd.

Cape Breton Regional Municipality

Consumer Advocate

Ecology Action Centre

Efficiency Nova Scotia Corporation

Electricity Ratepayers Association of Nova Scotia (ERANS)

Halifax Regional Municipality

LED Roadway Lighting Limited

Liberal Caucus Office

Municipal Electric Utilities of Nova Scotia Co-operative

Municipality of the County of Richmond

NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited (Applicant and Intervenor)

Nova Scotia Department of Energy; Nova Scotia Environment and Nova Scotia Department of Natural Resources

Nova Scotia Government and General Employees Union

Nova Scotia Land Owners and Forest Fibre Producers Association

Nova Scotia Power Inc. (Applicant and Intervenor)

Progressive Conservative Caucus Office

Small Business Advocate

Strait Area Chamber of Commerce

Union of Nova Scotia Municipalities