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(9:09 a.m.)

CHAIRMAN:

Q. Good morning, counsel. Mr. Ludlow, Mr. Delaney. Ms. Newman, any preliminary matters before we begin this morning?

MS. NEWMAN:

Q. No, Chair, no preliminary matters, just to comment for the record, I guess that our breaks will be at 10:30 and 12:00 a.m. this morning.

CHAIRMAN:

Q. Thank you.

CHAIRMAN:

Q. Mr. Kennedy, you can continue with your cross. Thank you.

MR. EARL LUDLOW AND MR. PHONSE DELANEY CROSS-EXAMINATION BY MR. MARK KENNEDY (CONT'D)

MR. KENNEDY:

Q. Chair, Commissioners, your indulgence. Mr. Ludlow, Mr. Delaney, I wonder if we could just turn to the issue of meters as a project and this is project B36. And as per--I wonder if we could just go to page B36. So the project, if I'm gathering correctly, calls for the installation of new meters and the replacement

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of some existing meters and the total cost for doing that is estimated at $1,174,000, is that correct?

MR. LUDLOW:

A. That's correct.

Q. Okay. And we have the absolute numbers there of the number of meters at 8,000 regular domestic meters and 3,000 AMR meters, but that's not the total number of meters that are actually being switched out, is it? There's more meters than that being switched out? I guess if we could go to PUB-42 and if you could just scroll down, please. So, in actual fact, if I'm gathering correctly, there's 9,800 meters to be replaced and that there's 8,800 meters being retired. So the schedule we're looking at before showed 8,000 regular domestic meters and 3,000 AMR meters for 11,000 as the total. And then if we could look at just one more, PUB-41, immediately preceding. Okay, so here we have a total of 11,000 new meters to be replaced which jives with the B36 page that we were looking at a minute ago, correct?

MR. LUDLOW:

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A. That's correct.

Q. And it gives us the breakdown of the number of each; 3,000 AMR meters and a total of 8,000 regular meters, so that's as per B36. So if you'd just go back to PUB-42. Could you just explain, if you could, what this table is, is this an all inclusive table or is this just the number of meters to be replaced and retired as per the five reasons above? There seems to be--yes, if you could help sort of shed some light on that for us, that might -

MR. DELANEY:

A. Okay, let's just look at the Math here. I'm going to follow it back and--okay, we need 3,000 AMR meters next year, this is on PUB-41, and those are meters that we're replacing for existing customers due to safety and access reasons. So that's that 3,000. The regular domestic meters are 8,000. We need 2,200 for new customers that will come on line next year, to service their needs. And 5,800 for existing customers. Now they would be replacements due to--well there are a number of items mentioned there, the most significant of which is the government re-test order

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that's required every year. So--let me just read this paragraph to -

Q. Sure.

A. - get my thoughts clear. Yes, it's quite clear to me here, the 9,800 meters that will be replaced, okay--I'm still reading.

Q. Yes, no problem, take your time.

MR. LUDLOW:

A. As I look at these two RFIs, Mr. Chairman, there's several things happening. First of all, if I take you to PUB-41, this breaks down the new customers and existing as Mr. Delaney said, totalling in to 11,000. In here in the AMR category we have two different types of meters; one being domestic meters for access and safety and the second being in the area of general service demand. That's a very small number, approximately 100 comes to mind, Mr. Chairman. Now, what's happening in these numbers as I see it, Mr. Kennedy, between there and PUB-42 is that that AMR process, combined with new customers, combined with the government re-test order process which would come back to item number one, we are basically in a process here of--how would I say it--I'm

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MR. KENNEDY:
going to have to go away from the numbers as I can't do it in my head at this point, it's not working for me, I'm sorry, I may have to straighten that out later. But we retired a bulk of these meters as highlighted. There is no intent here to increase inventory of meters, either in AMR or anything else. That's not the premise. We will only replace meters that are causing issues through AMR, as I said earlier, of safety and access and new customers and those dictated under the GRO process. My mind is not clicking as to why there's a discrepancy of 1,100 meters, 1,200 meters.

MR. DELANEY:
A. I think I know that it is there, just looking at the Math. Just to clarify the question, if you look at it, we're going to--you would think on PUB-41, the numbers should add up to 9,800, but we're going to salvage 1,000 meters from the AMR project and we used them. So that's--if you can consider that, the Math all adds up.
Q. So, the total number retired per PUB-42 is

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8,800. Per PUB-41, the total of new customer meters is 2,200 so that would be the 11,000, correct? Am I gathering correctly then that this replaced 9,800 as you say, the 8,800 is the net of actual new meters that you need to purchase so you're getting--you're re-installing 1,000 of the meters that you've got here as replaced or -

MR. LUDLOW:
A. Exactly, Mr. Kennedy, Mr. Chairman. If I take you to PUB-42, reason number four, replace versus retired is 1,000 differential and in effect, what that means is we're able to, and I think we used the word "scrounge" yesterday, I would use the word "salvage", three--one-third of those meters that are re-tested, rechecked and approved for re-service. And hence that's taking that number to approximately 11,000. That's the basis.
Q. So of those 1,000 meters that are being salvaged as its being put, am I gathering correctly that we could say that another way that 1,000 of the domestic meters that you currently have in service, you intend to replace with AMR meters. They're functioning

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normal, regular meters, but you're replacing them with new AMR meters?

MR. LUDLOW:
A. Well, I think the point here is that we will, Mr. Chairman, replace 3,000 meters with AMR meters. 1,000 of the 3,000 we're installing and replacing will be re-used elsewhere.
Q. And so, presumably, 2,000 of the 3,000 you're replacing are not useable, not salvageable.
A. That is correct, Mr. Chairman in that the 2,000 would then be retired for various reasons. They would be from broken glass, dials, holes drilled in them, etcetera, etcetera, etcetera.
Q. What is an AMR meter?

MR. DELANEY:
A. An AMR meter is "automated meter read".

MR. LUDLOW:
A. This is a new process and it's bringing technology into metering in Canada and in effect, the whole metering industry is in a state of change, Mr. Chairman. In particular, under the leadership of Mr. Allan Johnson and Measurement Canada, he is responsible for the Weights and Measures Act. And as such, Canada

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is still governed by the laws that would apply to the electro-mechanical meters which are the old springs, dials and magnets which are pretty much--well, by far the majority of what we have in our service territory. Now, the industry internationally, south of the border and Europe, has moved towards the age of electronics, Information Technology. And one of the key areas there is the ability for a meter to communicate to a remote device. And AMR provides the Utility, be it a water meter or in our case an electricity meter, to communicate through--I'm not sure if it's the right word, but Mr. Kennedy you'd know more about this, a wireless modem by VHF or by radio signal or some kind of signal back to a remote site and you can group read a meter. For example, in this case, I could read Sobeys' meter from here through the proper hand held device. My signal would go out, it would download its information back to me. The problem that has come in is that the regulatory regime in Canada is still based on the government re-test order process which is a six year sampling. And that's what's

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MR. LUDLOW:
described in PUB-42 under the item number one. That is the sampling process to ensure the accuracy of meters. Right now, personally, I'm Chairing this for the utilities in Canada on the issue of regulatory change regarding electronic meters. And as such, to get that regulation changed such that the sampling and testing protocol, as it applies to electro-mechanical meters, does not apply to the AMR. But today, and that's an engineering term, but today, under the laws of the land, it still applies. So we have to be very cautious as to how we migrate into the AMR piece.

So, right now, that's underway. The next stage of this would be AMT, which permits services of disconnects and other services that a utility would use. That is not what's being proposed here. Safety and access, to give you an example, has been the driver of our process here for AMR. Example being, early first quarter this year, a meter reader broke his leg in two places. Effectively, I'm not sure if he fell into the stairwell that was covered with ice, cased with snow, or snow

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cased with ice. Dogs--I know in a GRA here I had a lot of grilling on the issue of use of binoculars for reading meters due to inaccessible backyards. Those would be the types where we would bringing AMR into place.

Q. I just wonder if we could go back for a moment to B36 on that application itself, actually, the second page of that.

MR. LUDLOW:

A. B37 -

Q. It would be actually B37, yes. There we go, second page, yes. Okay the paragraph under "Operating Experience" says "The purchase of new meters", I guess that's "are necessary to accommodate customer growth and to replace deteriorated meters. The quantity of meters for a new customer is based on the company's forecasted customer growth. Quantity for replacement purposes is determined using historical data for damaged meters and sampling results from previous years." Okay, so then when we look at the project cost for the period 1999 to 2003, self-evident 560, 564,000 and so on up to 674,000 for the last two years; 2002 and 2003, if we can just go

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back a page, the proposal for this year is a 1,174,000. Then we're back in 2005 to more normal; 700,000, if I could say that. And the forecast for the following three-year period is similar. So could you explain to me what's driving the cost up this year to a 1,174,000 above what would appear to be your historical averages, if as it's stated under the "Operating Experience", the quantity for replacement purposes is determined using historical data?

MR. DELANEY:

A. The million one seventy-four, of course, includes the AMR meters that were installed in 2004 at a price of $360,000. The amount for--and that's a replacement program to handle safety issues, access issues. The regular Domestic which would be more in line with the history, in terms of regular replacements for GROs and installations for new customers, that value is $814,00. And it's based on the customer growth. 2004 we see it to be a high year for customer growth and that's the answer. The spike or the increase is mostly due to AMR.

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Q. Now your customer growth is only in the order of one or two percent a year, but your budget is up for this item, almost 50 percent. Or more than that, 100 percent.

MR. LUDLOW:

A. The government re-test order process is not something that we control, I'll start with that point as well. And the government re-test order process is based upon a series of specifications, testing and sampling dictated by the federal government under their regulatory regime. It will, in fact, hit the various types, makes and batches of meters that go back six, eight, ten years ago and they will in turn say you pull X number of meters and depending upon the failures, then it will determine where you go with respect to change-out of those meters. So that is something--well, that's basically the way it is operating. It is purely a statistical sample and order process, then moving to the change out or customer sampling order which is the basis of that test procedure. Now, it hasn't changed in the last three, four years, that is one factor affecting it. And as Mr.

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MR. LUDLOW:
Delaney did say, in the area of AMR, we do have a problem with respect to reading meters.
MR. KENNEDY:
Q. Okay.
MR. LUDLOW:
A. And with respect to the safety of our employees, that is first and centre.
Q. Sure. And just before we get to that safety issue, I just wanted to look at the cost a little bit more. I'm wondering if we could turn to, and I believe you just had the numbers there, but it might assist the panel to see where they can find them. And this is in Volume III, Distribution, Appendix I, that's it. So this is where we have the breakdown between the regular domestic meters and associated equipment costing 814 and the AMR safety and access costing 360,000. Are my calculations right that if you're replacing 8,000--purchasing 8,000 new regular domestic meters and the project cost is $814,000, does that work out to 100 bucks a meter, roughly?
MR. LUDLOW:
A. Two things. First of all your Math is--I

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don't usually bring calculators with me any more, I learned that a long time ago here. But I would think your Math is pretty much in the ballpark. I would think, as well--but there's a point to be remembered here and in my first explanation, I didn't bring it up. I refer you to your screen in front under "A" is regular Domestic meters and associated equipment. And the associated equipment that's involved here would include things such as--what's a word that's going to make sense--metering tanks or totalizers or current transformers. Mr. Chairman, by far the bulk of this category is new meters, but there is equipment involved with metering that's in here as well. And the reason it is here, it has always been here and what has happened, we have been finding that some of our metering tanks have been failing. In the past number of years we have revised our metering accordingly. But, this then brings in new equipment. This category of domestic meters and associated equipment, you need to be careful, it is not just straight meters. The cost of a new AMR meter, if it will be

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helpful, is approximately $86 and the cost of a domestic meter would be approximately, I'd give it -
MR. DELANEY:
A. $35.00.
MR. LUDLOW:
A. $35.00. I don't know if that will help your calculation, Mr. Kennedy.
Q. Sure, because if we take the 360 and we divide it by the 3,000 new AMR meters, you get $120.00 a meter. So -
MR. DELANEY:
A. There's another component that we have to look at. It's the balance of demand meters inside of that equation. And the difference between--a demand meter is a meter that we put on a general service customer, a customer with much higher load where we could measure the demand. And in the AMR balance of 3,000 meters, there's only 100 demand meters involved there, whereas in the 8,000 domestic meters, except for the regular meters, there's 800 demand meters. So you'd have to, in terms of doing your calculation as to what the per unit cost was, you'd have to look at that demand meter

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component within the two groups as well. And to give you an example there, an AMR demand meter costs $600 as opposed to the regular AMR meter which is $85 or $86 and a regular domestic meter would cost $300 as opposed to--a regular domestic demand meter would cost $300 versus 37, 35 dollars for the regular non-demand meter.
Q. So it's clear then that the AMR meters are, even on a unit basis, can be significantly more than the cost of a regular meter.
MR. DELANEY:
A. Yes, that's correct.
Q. Okay. And the rationale provided or justification provided for the purchase of these more expensive AMR meters is for the safety of your workers?
MR. DELANEY:
Q. Two issue here, Mr. Chairman. It's safety and access. And first of all, it is in the area of safety. Again, I gave an example, there are others. And the access problem is in the area of, I'm going to use the word at the danger of it probably coming back to me, it's the estimating area. We are finding areas

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MR. DELANEY:
that it's near impossible to get access to, either without going over fences or through people's houses and also some houses that have internal meters that we just can't read. So that's the basis of the two-prong drivers behind those 3,000 meters.
Q. Okay, if we could go to NLH-67 and NLH-67 asked to describe the employee safety improvements that would be obtained by using the new AMR meters, "Please list and describe any significant safety incidents that have occurred in the past five years that could have been prevented by use of an AMR." And the reply goes on to describe the safety and access issues that you've just described, Mr. Ludlow. Let's just leave the access issue aside for the moment and just look at the safety issue. Now, the question asked for, "Please list and describe any significant safety incidents that have occurred in the past five years." The reply to that seems to begin at line 19, "There have been a number of incidents reported over the past five years." Now that's not in reply to the question, is

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it. The question asks "how many in the past five years", so was it that that number is not tracked by Newfoundland Power or is there a reason why Newfoundland Power didn't provide a clear answer to that question?
MR. LUDLOW:
A. Bear with me one second, Mr. Kennedy, please.
MR. KENNEDY:
Q. Okay.
MR. LUDLOW:
A. It's my understanding, Mr. Chairman, that the question reads, "Please list and describe any significant safety incidents that have occurred in the past five years that could have been prevented by the use of AMR." And then we actually provided the individual incidents and described them--am I missing your question, Mr. Kennedy?
MR. KENNEDY:
Q. Yes, I think so because I guess the question then is, is this an all inclusive list of the incidents in the past five years that Newfoundland Power feels could have been avoided by using AMR meters. And if not, then it wasn't an answer to the question that was

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asked.
MR. LUDLOW:
A. I think the hinge of this question and the answer may be on "significant". When we talk in terms of accidents, we usually have a tendency to talk in terms of end results. These that I read here in my scan, represent lost time injuries or time that was not--the employee was not available for the next regular scheduled shift, rather than medical aid injuries, slips, trips, falls, soft-tissue injuries, as well as replacements to other jobs. And that's basically--it's certainly not intending to be misleading, Mr. Chairman. When we talk about significant accidents, we have a tendency to lean towards the lost time end.
MR. KENNEDY:
Q. Okay, so -
CHAIRMAN:
Q. Are you saying, Mr. Ludlow--excuse me -
MR. KENNEDY:
Q. Yes, sure.
CHAIRMAN:
Q. - that a punctured tire would be considered

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significant, but a soft-tissue injury would
MR. KENNEDY:
not?
MR. LUDLOW:
A. No. I guess where I was going there, Mr. Chairman, as I read through these, if you'd bear with me a second here, a dog was bitten by a meter reader (sic.)--I think I said that backwards again. I hope the record gets corrected on that. I have the distinct feeling I'm going to hear that again.
MR. KENNEDY:
Q. Possibly once.
MR. LUDLOW:
A. Sorry. Let's try again. The meter reader was bitten by a dog. In that case, that was a Newfoundland dog that effectively, almost removed the calf of a meter reader. So what I was getting in that point, in the case of a soft tissue injury, Mr. Chairman, what I was saying is if the meter reader slipped and had a sprained shoulder, he could be displaced to other work or would be put in other areas. So I wasn't demeaning the seriousness of the injury, but in this answer we've provided

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MR. LUDLOW:
primarily what I would call the more substantive lost time injuries which is the way we would refer to these. And I'm trying to get that balance in place.
(9:40 a.m.)
MR. KENNEDY:
Q. Okay, but for instance, the second reply there, "In May 2002 a meter reader suffered a knee injury as a result of falling into a snow-covered fence post hole." Now, that's not an access issue, that's just a hidden danger issue, correct?
MR. LUDLOW:
A. That's a fair assessment.
Q. So, it's not a safety issue that could have been resolved by the introduction of an AMR meter, unless you have an AMR meter on every single house.
MR. LUDLOW:
A. In this case, I have no idea where the fence post hole was and, generically, the way you're presenting it, or Mr. Kennedy is presenting it, Mr. Chair, I would have to agree. However, in this case, I don't know where this

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was, if this was the case of an enclosed fence, then I would say an AMR meter would have prevented it.
MR. KENNEDY:
Q. And the third one, "In March 2003, a meter reader slipped on an incline and landed on his back", but that really doesn't tell us whether the incline was of such a nature that it was an obvious danger that you would have wanted to avoid in the access issue. But it doesn't speak to how an AMR meter would have solved that issue, does it?
MR. LUDLOW:
A. No, I agree again with you that the wording presented in the response does not speak to whether this is a generic response or a specific one.
Q. And number one and number four are dog issues. So in the case where there's a dog that's preventing you from being able to have unencumbered access to someone's premises so that they can read the meter, is that not the problem of the person with the dog rather than all of our problems by having to foot the bill for more expensive meters to be put in their

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house so we don't encounter the dogs?
MR. LUDLOW:
A. It's a good question, Mr. Kennedy. But, Mr. Chairman, in reality, and I would say here, the amount of work and effort and the number of dogs that are actually connected to meter bases in this province is incredible. And as you move around, it's one thing to sit here and say yes, we get the dog put down. I'm sorry, we've tried that, that don't work. We've tried to get the dogs removed. Then we estimate the meters. But that can only go on for so long. And in effect, the ones that are highlighted here, are, you know, a few of the dog bites that we've gone into. This whole issue of dogs and meter readers and if you want to expand that to post--I'm going to say postman, no sexist comment--postal workers, the same type of problems they're running into. Now the reality of this is, this is much broader than just AMR and dogs. This is a by-product of it.
Q. But wasn't it the case that Newfoundland Power applied and received approval for purchasing these dog umbrellas a couple of years ago that

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you were going to hand out to your meter readers, which I believe the Company indicated were working quite well in order to fend off dog attacks?
MR. LUDLOW:
A. That's correct, called a bit terminator.
Q. And so this is another project that's based on dog bites?
MR. LUDLOW:
A. No, sir, I think the extension, Mr. Chairman, that's been applied here is incorrect. This is--we were asked to respond to one question that dealt with the injuries that would have been prevented. This project is being based upon two issues: safety and access.
Q. Okay, let's go to the access -
MR. LUDLOW:
A. No, let me--if I may finish please. The safety of our meter readers is something that is front and center. Getting to those back lots to read in a summer day is one thing; climbing fences is prohibited. These are the trouble spots we're into. So this is not hinged purely on safety, but it is certainly a factor.

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MR. KENNEDY:
Q. Okay, so let's just go to the access issue, we've got NLH-67 up, yes. And it's the second sentence in the reply. "These locations include back lot developments, row housing with fenced back yards, lots bordering on treed areas or slopes, inside meters, raised meter locations accessed by stairs or patios and customer specific issues, such as locked gates and roaming dogs." Okay, so the dogs are not an access issue per se, that's a safety issue?
MR. LUDLOW:
A. Well, I guess one could turn into the other, Mr. Kennedy.
Q. Fair enough. But in the case of back lot developments and row housing with fenced back yards, who is it that decides where the meter goes in order for a meter reader to be able to have access to it?
MR. DELANEY:
A. That would be a decision that we would make, our engineering technicians. And we very much, with respect to the location of the meter, is probably the biggest criteria in

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terms of location of the meter, where do you put the meter on the house? And we strive to put the meter on the side of the house to make it as easy and accessible as possible for the meter readers.
Q. If a meter is inaccessible by virtue of being inside a building, is that meter installed by Newfoundland Power?
MR. DELANEY:
Q. Meters inside buildings, many of these, in terms of domestic residences, some of these inside meter installations dated from early 60's, date from way back. It is not a modern thing that we do at all in the last large number of years. Now in the case of commercial properties, meters are typically located inside--in terms of a commercial property with multiple customers, there are designs where the meters are intentionally put inside, in an electrical room and we would have access with keys in that case.
CHAIRMAN:
Q. Such as, can you give me an example?
MR. DELANEY:
A. Such as a mall where you may have individual

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services for each store in the mall, so the electrical inside would be--now an inside meter.
MR. KENNEDY:
Q. But you're not--it's an inside meter, but you're not prevented from having access to those meters if it's in a mall?
MR. DELANEY:
A. No, not in that case, that wouldn't be an example of a problem with access.
Q. Right.
A. Not unless we - no, okay.
Q. You just mentioned there that some of these meters date back to the 60's. What would be the average life of a meter, a regular domestic meter?
MR. LUDLOW:
A. Domestic meter could run, the average life of the entire population we have? I'm sorry, I don't have that, Mr. Chairman.
Q. What's the expected life, yeah, of a -
MR. LUDLOW:
A. I would suggest we can get fifteen years, possibly a little longer, twenty.
Q. Do you know what the depreciation rate is on

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your meter category?
MR. LUDLOW:
A. I would have no idea, that's one that I would defer to Mr. Perry.
Q. Would you be able to provide that to us, kind of an undertaking to have the depreciation rate for the meter classification and your asset and your rate base - (undertaking)
MR. DELANEY:
A. Sure.
MR. LUDLOW:
A. Yes, Mr. Chairman.
Q. If I'm calculating correctly, if you're replacing 11,000 meters and you have roughly 212,000 customers, then you've got about a 5.2 percent replacement rate based on those numbers?
MR. DELANEY:
A. Well with the AMR project in there. Now the AMR project is for 2004, you do not see the AMR beyond 2004.
Q. Okay. So we would go back to more normal 8,000 meters being replaced each year?
MR. DELANEY:
A. That's what is indicated in the forecast, yes.

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MR. LUDLOW:

A. Mr. Chairman, there's a point on this regarding the access that I would like to add, if I may at this point, regarding General Service Customers at that point. When we speak in terms of access, it's not that the access is not necessarily available in the General Service, however, we maintain locked boxes of keys to the tunes of hundreds of keys. For example, pubs on George Street, stores on Water Street and that in itself is posing significant--I wouldn't call it responsibility, I'm not shy of responsibility, but is getting in, getting through it, the organization, the timing and all of those issues are part of this access issue in the General Service side, by far the minority represented here. The Domestics, they go back and any house that was built back in, I would go up to the early--late 60's would be interior. It is a fair statement, we inform the customer where to attach the meter and the service to the house, but it is not a fair assessment to say that we tell them where to build their fences. The meters when the

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places are built in row housing, an example is being Cumberland Crescent, you can go up to Cowen Heights area in some areas, the meter, when a house is built, is easily read. But after development by the landowners and the control of fencing that goes back in a cube or a square, it's impossible to access without going through the house.

Q. Okay, which takes a longer period of time?

MR. LUDLOW:

A. Which is sometimes impossible to do, first of all, because it's in the wintertime, the meter reader, first of all--you want the logistics, we've got creepers, ice--what's the word I'm looking for, something to increase the friction (phonetic) on ice shoes. Footwear, assuming there's someone home, you might get through the house. Now, timing of that, I don't mind having someone take their boots off, that's not my point. The reality is if they're not home, we can't get the reading, so that becomes--I want to clarify the point about location of meter verses when a house is built verses where it is today and accessibility today. And it is a very

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important point.

Q. Sure, but if we're just dealing with access and not safety, then the introduction of AMR meters in order to improve access so that you're more efficient in the meter reading process -

MR. LUDLOW:

A. And accurate, sorry, I didn't mean to interrupt you.

Q. No. Would that then not require Newfoundland Power to provide a net present value calculation to show that spending this money now on AMR meters is going to save money later by increasing your operational efficiency in regards to meter reading?

MR. LUDLOW:

A. Well, can an NPV by presented on the fact of operational efficiency alone, Mr. Chairman? I'm sure that we can look at the operational efficiency; however, where this becomes a real issue is what operational efficiency and value do we put on multiple estimates as a result of not being able to make contact with those meters and read them. And what value do I put on that person's leg in the safety side. So

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do I do an NPV on the AMR meter, which is based on one third of the parameters? In my view, that is inappropriate.

Q. Okay, I'd like to change topics if I could, and I'd just like to look at part of the project under your distribution reliability initiatives involving a lightening arrester project, and if we go to volume 3 and it's under "Distribution", appendix 2, let me look at that first. If we could just scroll down a little bit please. Okay, the total project costs for this rebuilding distribution lines is, on the feeder upgrade portion of the total project is $2,802,000.00. And if we just scroll down, you'll see that under "Operating Experience, see the following reports outlining the deficiencies associated with various components." And then one of them is distribution lightening arresters. I'm going to look at the details of that in a moment, but I'm just wondering would you have at the ready there how much of this $2,802,000.00 for feeder upgrades relates specifically to the installation of lightening arresters?

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MR. DELANEY:

A. The amount, I don't have the exact number, but we're looking in the ballpark of $300,000.00.

(9:55 a.m.)

Q. Okay, thank you, Mr. Delaney. Okay, let's just look then to the specifics for the lightening arrester which would be under Attachment B, and as I understand it and as I think has been indicated in a response to an RFI, the principle--the support or rationale for this project is economic?

MR. LUDLOW:

A. Yes.

Q. Now the report that we have under that Attachment B, provides some details about what's occurring, what has occurred in the past and so on, and then it conducts some present worth calculations and provides some alternatives. And if we turn to page 3, okay, so as indicated under the heading "Transformer Failures Due to Lightening", the second paragraph there, it says, "Over the past 13 years, Newfoundland Power has lost in excess of 1,500 transformers that have failed due to lightening, with approximately 700 of these in

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the last five years and the annual number of units that have failed range from a low of 22 units in 2000 to a high of 323 units in 2002. And the average over the past five years has been 139." And this translates to an average annual cost in excess of $300,000.00 per year and as per the foot note, it's based on the unit cost from Appendix A and 139 units. I wonder if we could, just for a moment, go to PUB-132. And so as per the reply to PUB-132, this was the actual lightening cost failure rate and transformers for each of the five years that were referenced in that paragraph, 1990--well this was 1998 to 2002, and is it fair to say looking at that table or do you agree with the statement that much like lightening itself, these are rather erratic results in the sense that there doesn't seem to be any trend or predictability to the number of transformer failures that may occur in any given year or over any period of time based on lightening strikes?

MR. DELANEY:

A. Looking at the period 1998 to 2002, we see two years with a lot of failures, the 254, 323

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failures and three years with a small number of failures for an average of, I think it's 139 or 140. That's a five-year period and there's a great variance there. If we were to look at NLH-48, Newfoundland and Labrador Hydro asked the same sort of question and it gives a bit more history.

Q. Okay.

MR. DELANEY:

A. Here we have the lightening--the distribution transformer failures going back to 1993, which show a little bit more pattern to the data, showing that 99, 2000, 2001 were extraordinarily low in the context of a ten-year pattern, so coming out of that, we have an average over the ten years of about 140.

Q. And when you say about 140 as an average, that's just a simple average of that ten-year period?

MR. DELANEY:

A. Yeah, it's somewhere around there, and as a matter of interest, so far in 2003, we've experienced 140--exactly 140 distribution transformer failures due to lightening--that's so far.

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Q. Sure. And the report itself that we were just looking at, the Arrester Report at page 2, said "While it may be difficult to predict whether long-term weather and lightening patterns in Newfoundland are changing, it certainly appears that the incident and severity of lightening, at least in certain areas of the province, have increased over the past decade." So could I ask and I assume you're not the author of this report, obviously, but what forms the basis of the conclusion that it certainly appears that the incidence and severity of lightening, at least in certain areas of the province, has increased over the past decade? I don't see that in NLH-48 or in the previous one that we were looking at.

MR. DELANEY:

A. Yeah. To give some--in a way, that answer is somewhat antidotal, but there is some math behind it and that's referred to in NLH-51, a RFI from Hydro, where I can read the last sentence which basically says the average number of transformer failures due to lightening over the past 13 years has been

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MR. DELANEY:
about 115, while over the last five years the average has increased to 140. So that's some substance behind that statement.
Q. But then the previous paragraph to that reply in the second sentence, or actually the first sentence, you go, "Other than information related to transformer failures due to lightening activity, Newfoundland Power does not have any other evidence to support the proposition that the incidence and severity of lightening related damage in certain areas of the province has increased over the past decade, or that there will be an increasing trend in the future."
MR. DELANEY:
A. Yeah, and the only evidence we have, we go on to say is the comparison of the averages based on how long you're going to look back. Thirteen years, the average is lower than the average in the last five years.
Q. Okay, now I'm not a statistician, thank God, but it seems to me that using simple averages to determine the likelihood of a lightening strike in a given year, based on the data as

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provided in NLH-48, for instance, would seem to be rather simplistic, would you agree, when the data is that erratic, would you not normally use a more sophisticated tool to determine whether there's trend lines or normalizing the data somehow?
MR. DELANEY:
A. Like yourself, Mr. Kennedy, I'm not a statistician either, so I would not be able to answer that question.
Q. Okay.
MR. LUDLOW:
A. Could I just help a little, if I may, on this one?
Q. Go right ahead.
MR. LUDLOW:
A. If we look at lightening, we base this here on our past practice of installing lightening arresters on distribution transformers and we have not done it. That was a decision we made back in the '60s and '70s. And what we are finding that by the very nature of lightening hits, it's happening in the summer time, it's--I guess nature is sporadic--but it's diverse. I've spent myself, 20 odd years in this

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business and I can speak personally, although anecdotally, that we are getting a lot of lightening in the last three or four years and in particular spots. And that's where we started this process back around 1995 was to select individual areas, the Grand Falls area, the Lethbridge area, Stephenville area, parts of Conception Bay. But as we look at how to move forward with this process, straight averages, I would agree is not the best tool. Should we be using correlations? I don't know. But at the end of the day the incremental cost to a pole mounted transformer is $53.00 approximately to put the lightening arrester in place, to protect that unit.
Now, as we go--that's for new units as we move forward, Mr. Chairman, 53, it's in that range anyway.
MR. DELANEY:
A. On the unit that cost approximately $2,000.00.
MR. LUDLOW:
A. Then as we go through and do our distribution system sweeps and inspections, we go by these transformers and not to put them into that type of unit when you're already up there at

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the unit, logically is the time to move and do this and it is a sound decision, both engineering, catastrophic failure of these units. Let me give an example, Mr. Chairman. In, about three weeks ago, maybe a month ago, a very severe storm went through the Placentia, Argentia area and came up through the bottom, I do believe of either Trinity Bay or Conception Bay. We lost a fair number of transformers. Now, there was probably a 100 to 150 fuses open, a lineman climbs that pole, closes the switch on the hope that he hasn't got a catastrophic failure within that tank. What we have been finding, in the areas where we have installed lightening arresters in the past few years, we have a had a minute number of failures of those transformers. The number escapes me, but I've got seven in the back of my head. It's a very small number. And of those seven, many of them were direct hits. So, we weren't looking for the arresters, we were looking for the tops and the bushings and the coils of the transformer that had literally blown out of the pole. So, putting that together, combining simple arithmetic

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MR. LUDLOW:
averages with the anecdotes of long service employees and field experience, that's how we arrived at our movement forward, combining that with our distribution and liability issue.
Q. Okay. Ultimately through, as you indicated earlier, the justification for this project has to be one base--justification is reliability, but the analysis ultimately has to be economic
MR. LUDLOW:
A. I agree.
Q. Okay. And as is indicated in the cost estimates that are attached as Appendix A to the Arrester Lightening Report. All right, if we could just go through that so that I make sure that I understand this correctly. So, here what we're doing is we're calculating the number of transformers lost in 2002 lightening storms. And it's footnote there after "Transformers Lost", it's the number of transformers represents losses from August 13 to August 27, 2002 and the number is 233, correct.

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MR. DELANEY:
A. That's correct.
Q. Okay. Now, is there a reason why you use 233 transformers lost when P.U.B 132 indicated in 2002 it was 323 transformers lost?
MR. DELANEY:
A. The reason we use that number is to get us the most accurate indication that we could of what the transformer, the cost of replacing a transformer. During that period we had severe lightening storms coming through Newfoundland, through central Newfoundland. And in terms of the testing the economics on this, we thought that this would represent the lowest cost or if it was a conservative estimate in determining replacement of the transformer because we were engaged in replacing transformers at that time because there was so many had been lost, 233 during that week. And there's a certain economy of scale, I guess, that happens when you are at that activity and everyone is at that activity. So, the cost of replacing 233 units in one small time should be the smallest cost that you will see, rather than replacing, say, one unit at a time. So,

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we're pretty comfortable that we've got a conservative estimate as to the per unit cost to replace a transformer.
Q. Per transformer, okay. Then you do an estimate of the cost to install a lightening arrester.
MR. DELANEY:
A. That's correct.
Q. Okay. And is this done on the same basis of this is how much it would cost if you were replacing, if you were installing lightening arresters in quantity because there's nothing to indicate that on the calculation. If we could go to the next page.
MR. DELANEY:
A. The material cost will not change. If you're installing arresters in quantity or if you're installing them one at a time in more of a sporadic manner. However, on the labour side of it, it will change if you are taking an organized productive approach versus installing them, so to speak, one at a time on occasion. The two cost estimates related to the labour for installing lightening arresters are based, first like I said, on just doing

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that one activity. And second, it's doing it as part of a bigger project. Now, I'll have to step back and inform the Board as to why we're doing that.
We will, over the next number of years, be phasing out PCBs or doing a PCB phase over our distribution feeders. And that involves visiting--I don't have the exact number--but it involves visiting a significant percentage of the distribution transformers that are in the system to test the oil in the transformer as to whether it contains PCB or not. And we have objectives in terms of getting PCBs out of the distribution system. So, Earl eluded to this earlier, that if you're at the distribution transformer testing for PCBs and it's on a feeder that's experienced, say, we've picked more than three lightening in the last number of years, last five years, it would make sense from a productivity perspective to install a lightening arrester while you're there which is a $50.00 unit, about this high, you can install a lightening arrester while the crew is there doing the PCB inspection. As well, there are other things

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MR. DELANEY:
we're doing on feeders, sleeve replacements, cut out replacement is another thing. And we refer to this in several reports in the document. So, we've included two labour estimates in our analysis. One just going there and doing the lightening arrester. Second, which is approximately half of the original estimate for labour, is doing it in conjunction with other work. So, those are the two labour estimates on that page.

Q. Okay. So, when we look at the next page, cost alternatives, if I could just look at alternative number two first and as was indicated, this alternative involving an arrester on every transformer within Newfoundland Power's service territory as a stand alone project. So, is it accurate to say that this alternative is based on a massive one time event of Newfoundland Power going out and installing lightening arresters on all 43,400 transformers that it has in its system.

(10:13 a.m.)

MR. DELANEY:

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A. That's what it is, that's go out and install them. And I'll add, by the way, that we're somewhat unusual in Newfoundland not to have that already done. The vast majority of utilities in North America have lightening arresters installed on all their distribution transformers.

Q. Newfoundland is an unusual place sometimes. But if we could just flip back a page. Okay, well, just before we do that, under that alternative two, you've got the average cost to install a lightening arrester is $150.94.

MR. DELANEY:

A. That's correct.

Q. Okay. So, if you flip back a page, as I understood it, that $150.94 is if you were installing--it would be the labour--I guess what I'm asking is where's the $150.00 come from?

MR. DELANEY:

A. It comes from a two-person crew, I think that's one hour of labour at $63.65, that's the labour, that's the salary plus the overheads, the fringe overheads on that labour. And then we take our standard

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percentages with respect to the cost of the line truck that goes along with that labour, the cost of the engineering which would be the set up, organization, planning of the job and the vehicles associated with the engineering to add up to $150.00 and that's one hour of labour to install a lightening arrester.

Q. Okay, but I thought that the $78.74 was the number that we used to, that we should use to see what the cost was to install a lightening arrester if it was being conducted in an unmass, you know, if it was a massive one time project.

MR. MYLES:

Q. Excuse me, Mr. Chairman, there seems to be some confusion here. If I can assist it might help. There are two estimates shown on that page, not one.

MR. KENNEDY:

Q. Two estimates shown on which page, counsel?

MR. MYLES:

Q. Page two.

MR. KENNEDY:

Q. Cost estimate to install.

MR. MYLES:

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Q. Right, and that's where it gets down to $150.94, just -

MR. KENNEDY:

Q. Yes.

MR. MYLES:

Q. And then the second cost estimate is a part of doing it with other work and that's your $78.74.

MR. KENNEDY:

Q. Yes, I understand that. I think the witness has explained that.

MR. MYLES:

Q. It wasn't clear from your question.

MR. KENNEDY:

Q. So, the question I have, Mr. Delaney, is of those two figures, one involves the labour for $150.94, correct?

MR. DELANEY:

A. Yes, that would be the labour of doing one lightening arrester on a transformer with no other project involved, sending the crew to go out and install lightening arrester on distribution transformers.

Q. Okay, but does that $150.94 then include--it doesn't include the cost of the material

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MR. KENNEDY:
itself? That's just the labour, isn't it?
MR. DELANEY:
A. That's just the labour, yes, the material would be $54.67 above, it's noted above.
Q. Okay.
MR. DELANEY:
A. And there are two ways of looking at the material cost as well, just to clarify that. First, the arrester bracket, that's $6.18, that would be for a new installation that comes in, new transformer. Whereas the, we call it without the boss, that's for an older transformer unit where we have to install a different type of bracket to get the lightening arrester on.
Q. Right, but just to go back, the $150.94 is the labour component to install a lightening arrester on a pole, correct?
MR. DELANEY:
A. That's correct.
Q. Okay. And that would be if you're doing it on a ad hoc, one-by-one basis?
MR. DELANEY:
A. That's correct.

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Q. Okay.
MR. DELANEY:
A. That is the specific project they're going to, yes.
Q. The material is $54.67.
MR. DELANEY:
A. Yes.
Q. And that's $54.67 independent of whether you're doing it ad hoc or in mass, the material is the material cost.
MR. DELANEY:
A. Right.
Q. Okay. The $78.74 is what you feel it would cost, material included, if you were doing it on a massive scale?
MR. DELANEY:
A. No, that's not correct.
Q. Okay, so what's the $78.74?
MR. DELANEY:
A. That would be the labour that we would apply to the lightening arrester project if we were doing it unmass in addition to other projects.
Q. But if you look at your table, Mr. Delaney, under, it says material equals $54.67 to total $78.74.

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MR. DELANEY:
A. Oh, okay, sorry, sorry, yes, sorry. I've just misread that. The material cost is $54.67 including, that would be included in the total.
Q. Right. So, we're comparing roughly $204.00, $205.00 per lightening arrester if done ad hoc, to $78.74 if we're doing it on a massive scale, is that correct?
MR. DELANEY:
A. That's correct.
Q. Okay. Because if we go to the cost alternatives, the next page.
MR. LUDLOW:
A. Mr. Chairman, if I may just come in, when we go to a pole, the lightening arrester is one of maybe six projects at that pole. Fair?
MR. DELANEY:
A. There are several other projects, yes.
MR. LUDLOW:
A. Such as PCB testing, such as cut outs, the sleeves and so on. And if it is done in conjunction with going to the pole and installing the lightening arrester, you get the benefit, an economies of scale, you're

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there. You're mobilization and demobilization is significantly reduced. That's the concept behind it.
Q. Okay. So, if we go back, this average cost to install a lightening arrester, you've got $150.94 there and the number of transformers is 43,400, would give you a total cost of $6,550,796.00 which is the product of those two numbers, 43,400 times $150.94 gives me a total cost of $6,550,796.00. And then you go present value 30 years and I'm not sure where that comes from. Could you explain what that is, what the adjustment is to go from the $6,550,796 to the $6,894,379.00.
MR. DELANEY:
A. Yes, going further on in the report in Appendix B, it would be under Alternative 2, there is a spreadsheet that shows the detail, the present worth calculation.
Q. Okay.
MR. DELANEY:
A. And I can go through the intricacies of the spreadsheet if you so desire.
Q. No, I don't think so. Just if you can give us the -

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MR. DELANEY:
A. It's a present worth analysis is, you know, the big number there, the important number to look at is the weighed average incremental cost of capital and that's the rate at which you're discounting all the future cash flows back to get a present value.
Q. Okay.
MR. DELANEY:
A. So, that's where the calculation is done in detail, is on this page.
Q. Okay. So, just go back again though to, if we could, to that cost of alternatives. It would be under, I think if you just go Appendix, yes, the next page and then the next page again, cost of alternatives, there we go. So, if we just scroll down so we've got Alternative 2 and Alternative 3. Okay, so in the case of Alternative 3, you've got the number of transformers to be replaced over a five-year program, installing an arrester on every transformer would be 19,325 transformers. Then use the average lightening arrester cost of $78.74 and as we ascertain the $78.74 is both material and labour -

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MR. DELANEY:
A. That's correct, yes.
Q. - but the previous Alternative number 2, average cost to install a lightening arrester of $150.94 is only the labour and not the material.
MR. MYLES:
Q. Mr. Chairman, I don't mean to interfere, but it may be appropriate to stop at this point. I think that the problem that I'm foreseeing is the manner of presentation and some confusion that's resulted from that. And maybe if I can discuss this with counsel and the witnesses, we be able to truncate this. I'm reading that material differently and we're taking a lot of time on this and I think we may be able to sort this out very quickly.
CHAIRMAN:
Q. Well, i's just about 10:30 in any event, so we'll take 15 minutes.
MR. MYLES:
Q. That's fine, chair. Thank you.
(BREAK - 10:23 A.M.)
(RESUME - 10:47 A.M.)
CHAIRPERSON:

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Q. Okay. Are we getting sorted out?
MR. KENNEDY:
Q. I believe so, Chair. Mr. Myles, counsel for Newfoundland Power, is going to address his witness in order to be able to straighten out the record before I recommence my cross-examination. We felt that would be the most appropriate thing to do, if that suits the Board.
CHAIRPERSON:
Q. That's fine.
MR. KENNEDY:
Q. Thank you, Chair.
MR. MYLES:
Q. Thank you. Just for the record, we are in Volume 3, Distribution Appendix 2, Attachment A, Appendix A which is entitled costs, and on page two, we have the cost estimate to install lightning arrestor. Mr. Delaney, I'd like to take you through the calculations at the top. Under "material" you see a total material cost and that is how much?
MR. DELANEY:
A. The total material cost is $54.67.
Q. All right. Now actually to move down, two

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lines under the heading "labour, working foreman and lineman" and that gives you a total of 48.96?
MR. DELANEY:
A. That's correct.
Q. All right. And the next line is doing what?
MR. DELANEY:
A. The next line is applying the overheads to the labour, which brings it up to $63.65 an hour.
Q. And does that represent the total labour for those two people?
MR. DELANEY:
A. That's correct.
Q. All right. So now we'll be adding that to the 54.67?
MR. DELANEY:
A. That's correct.
Q. All right. Now the next line is for the line truck and that's 13.37?
MR. DELANEY:
A. Correct.
Q. Okay. The next two lines, they are for engineering and vehicle?
MR. DELANEY:
A. That's correct.

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MR. MYLES:
Q. Okay. And would they be added together as well?
MR. DELANEY:
A. They would be added to give a total of $150.94.
Q. All right. So during your cross-examination, you had stated at one point that you needed to add total material to the total of 150 to get the total cost. Was that correct?
MR. DELANEY:
A. That's what I--yes, that's correct.
Q. Okay. But what is the actual total cost of material and labour and all other associated costs for the installation of the lightning arrester?
MR. DELANEY:
A. The total cost of the material and labour for the installation of the lightning arrester is $150.94.
Q. And is that a straight comparison to the number below, showing the side total of 78.74?
MR. DELANEY:
A. Yes, that is.
Q. Those are apples and apples, if I can say

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that?
MR. DELANEY:
A. The 78.74 includes material and labour plus overheads. The 150.94 includes material and labour plus overheads.
Q. All right. And when we go to the next page for cost of alternatives, under "alternative two" you see average cost to install a lightning arrester, the 150.94?
MR. DELANEY:
A. Yes, it is.
Q. And that's the correct number?
MR. DELANEY:
A. That's the correct number.
Q. And that's total material and labour?
MR. DELANEY:
A. That's correct.
Q. All right. Similarly, under "alternative three" the average lightning arrester cost, again that's the total?
MR. DELANEY:
A. That's the total, yes.
Q. All right. Thank you. I have no further questions.
CHAIRPERSON:

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Q. Thank you, Mr. Myles.
MR. MYLES:
Q. Pardon me?
CHAIRPERSON:
Q. Thank you.
MR. MYLES:
Q. And I should also apologize for the presentation. I should have picked that up when I was reviewing the material.
CHAIRPERSON:
Q. Ready to continue, Mr. Kennedy?
MR. KENNEDY:
Q. I am. Thank you, Chair, Commissioners. Gentlemen, just a few final questions on this project. If we could go back to the--I think we're already in Appendix A Costs, yes, and let's just go back to the estimated costs of a transformer failure. Okay. So as shown on the table, Newfoundland Power calculates that the total average cost per transformer is $2,221.10, correct?
MR. DELANEY:
A. Yes, that's correct.
Q. And this is based on a breakdown of the numbers as indicated for material and labour

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that were incurred as a result of transformers lost during an August 2002 lightning storm.
MR. KENNEDY:
Is that correct?
MR. DELANEY:
A. That's correct.
Q. So these costs are actual costs that were tracked by Newfoundland Power associated with the replacement of the transformers that were damaged during that lightning storm?
MR. DELANEY:
A. Yes, that's correct.
Q. Okay. So the next page, the cost estimate to install lightning arrester. The first figure, the material cost of $54.67, you've got a subcalculation in there for your surge arrester, 9Kv 38.30 and 18Kv 55.20, average cost of 44.05, and you say "note: the transformer split is approximately 34.66 for a 25 versus 12 1/2 Kv." Could you just explain that?
MR. DELANEY:
A. Okay. What that is, again obviously mention here I came up with this table, it's a 9Kv surge arrester would be applied on a

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MR. DELANEY:
transformer rated at 12.5Kv and a 18Kv surge arrester would be installed on a transformer rated at 25Kv. So the split in the system of transformers is 34 percent, 34 percent being 25Kv and 66 percent being 12.5Kv. So that's to determine the appropriate split amongst--between the 9Kv and 18Kv surge arresters to apply the average cost.
Q. So when it says average cost, is that a weighted average cost? I didn't have my calculator.
MR. DELANEY:
A. I don't have a calculator with me here. I would -
Q. It looks like just an average, 55 and 38 comes to $46. 55 and 38 comes to 46, so -
MR. DELANEY:
A. That would apply, it's a weighted average, based on the ratio, yes.
Q. Weighted average, okay. And so that's one assumption is that your--okay. And just down in your labour, you take your gross labour of $48.96 and you grossed it up by 30 percent. Is that an overhead burden?

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MR. DELANEY:
A. That would be some of the fringe percentages placed on labour, include things like Worker's Compensation. For every hour of labour we pay a Worker's Compensation fee. There's pension in those and I'm not familiar with all the overheads that are applied there, but it's a standard number.
Q. And then your provision for your line truck and your engineering is a percentage of your labour?
MR. DELANEY:
A. That's what we do the estimating in our capital projects, yes.
Q. Okay. So that's the same technique you use in estimating a capital project?
MR. DELANEY:
A. Yes. We apply percentages of the labour to come up with cost estimates for capital projects.
Q. And I notice your vehicle is 21 percent of engineering?
MR. DELANEY:
A. That's correct.
Q. And then engineering is 25 percent of labour?

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MR. DELANEY:
A. Yes, that's correct.
Q. Okay. So if our labour number--sorry, gross labour number, 48.96, okay, and then we provide those and we get the 150, all right. Now down in the 15 minutes for the calculation of how much it would cost based on a 15-minute time for installation -
MR. DELANEY:
A. Yes.
Q. - can I ask you what that's based on, the 15 minutes, and what you would feel to be the margin of error on that estimate of 15 minutes?
MR. DELANEY:
A. The 15 minutes is based on our judgment with respect to how much it would cost to install that lightning arrester in conjunction with other jobs at that same pole, the additional 15 minutes. I couldn't comment on what the ratio, the percentage of variance in that. I think it's a fair estimate myself.
Q. Okay. If we just go to the next page, cost of alternatives, and as is indicated with those inputs using an average of 139 transformer

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failures in a given year, the average cost per transformer based on the 2002 lightning storm of $2,221, you get an average annual cost of failure of $308,719, correct?
MR. DELANEY:
A. That's correct.
Q. And that derives a present value over a 30-year time span of 4,389,000?
MR. DELANEY:
A. Yes, that's correct.
Q. Okay. And if we just go to NLH-55, this requested that Newfoundland Power to just use the period 1998 to 2001, 1998 of 254 failures, 1999 44, and 2000 22, and 2001 50. You therefore averaged it to 93. You just took a simple average again?
MR. DELANEY:
A. Again, we took the average between '98 and 2001 for that calculation.
Q. Right, okay. But again, you didn't do any normalizing or smoothing out of the data to take into account the spike in 1998 of 254 failures as opposed to the failure rates experienced in 1999, 2000 and 2001?

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MR. DELANEY:
A. Could you repeat that again?
Q. Maybe it will help just if we could just briefly go to PUB-132 again. So this question
MR. KENNEDY:
asked you to ignore the 2002 data where you have the 323 failures and as is indicated, you had 254 failures in '98, 44 in '99, 22 in 2000 and 50 in 2001.
MR. DELANEY:
A. And we took the average, pretending 2002 didn't exist, yes.
Q. Right. So you just took a simple average again of those four years and you arrive at 93?
MR. DELANEY:
A. Exactly, yes.
Q. Okay. And so just going back to NLH-55, that when you do that and recalculate, the alternative number one, which is the do nothing alternative, status quo alternative, now gives it a present worth of 2,943,000?
MR. DELANEY:
A. That's correct, yes. It's still more expensive than alternative number three.

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Q. Sure. The 2,943,000, that's down from the original 4,389,000 which was your original alternative one based on 139 failure rate?
MR. DELANEY:
A. Yes, it has. If we remove the fact that we lost all those transformers in 2002 from the equation, we will get down to that present value.
Q. Right, okay.
MR. DELANEY:
A. Which is still higher than the -
Q. Sure.
MR. DELANEY:
A. - alternative we're proposing.
Q. Would you agree with me though that, for instance, if you're off on your estimate of the amount of time that it's going to take to install the lightning arrester and that instead of 15 minutes, it would take you a half an hour, alternative three is likely to be more expensive than alternative one?
MR. DELANEY:
A. If you were to say a half an hour, but we're saying 15 minutes would be the incremental cost of putting on the lightning arrester. A

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half hour is way too much.
Q. Okay. That's all the questions I have on lightning arresters. I'm sure people are thankful. I have one question concerning the Corner Brook transformer project, and if we could go to Volume 2, Substations, Appendix 4. I just have a specific question. There's a document here that, from a layperson's perspective, seems to imply the opposite. As I understand it, the basis of your project to increase your transformer capacity in Corner Brook is that you're currently topping out the capacity of the existing transformers?
(11:02 a.m.)
MR. DELANEY:
A. Yes. The -
Q. They're exceeding their load limits?
MR. DELANEY:
A. The combined capacity of all the substation transformers in Corner Brook will exceed the rated capacity of those units and we've done a number of things over the years to defer this project by switching loads back and forth between the transformers in Corner Brook, and we're at a point now where that approach is no

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longer feasible.
Q. Okay. If we could just go to--there's an attachment or sorry, an appendix A in that--so if we go--this is one of these, substations Appendix 4, Attachment A, Appendix 4, Appendix A.That's correct, 4, yes, and the first page of that. Okay. When I look at this table and I look at the various transformers and their rating and then look at the peak 2002 and the forecasted undiversified peak for 2003, it's clear that it's, in the case of Walbourne, expected to exceed, in 2003, if it hasn't already done so, exceed the rated capacity of your transformer there, correct?
MR. DELANEY:
A. That's correct.
Q. Now I couldn't see where there were any other ones here that would exceed your transformer capacities. When you follow up through the line for 2003, the rest of them seem to be within the existing transformer capacity.
MR. DELANEY:
A. Okay, I think you have to -
Q. Like if I look at Walbourne's T1, I have an existing MVa capacity of a transformer there

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MR. KENNEDY:
of 20 and the forecasted undiversified peak for Walbourne's in 2003 is 17.9.
MR. DELANEY:
A. 17 point--okay.
Q. Am I reading the table right?
MR. DELANEY:
A. Yes, you're reading the table right.
Q. Okay.
MR. DELANEY:
A. I just need to explain what's in there. First of all, substations like Howley, Deer Lake, Marble Mountain, Pasadena, we have to dismiss because they're not part of this whole equation. They're in different geographical areas.
Q. Okay. Which ones are we dismissing? Howley?
MR. DELANEY:
A. Yes. Well, it would be better to look at the ones we're going to include.
Q. Okay.
MR. DELANEY:
A. We're going to include the two units at Walbourne's, T1 and T2.
Q. Yes.

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MR. DELANEY:
A. The T3 unit at Humber.
Q. Yes.
MR. DELANEY:
A. Okay, which operates at 12.47Kv. We cannot include the T2 unit at Humber because it operates in a different voltage, and if we -
Q. Okay.
MR. DELANEY:
A. - were to get into that, we would be into a very much more expensive job. And Bayview T1.
Q. Okay.
MR. DELANEY:
A. Okay. So those are the three, yes, Bayview, Humber and Walbourne's, and -
Q. Okay, yes.
MR. DELANEY:
A. - and with Bayview, I see a--all right, so-- and again, we're getting into the math here. So Walbourne's, plus Humber, plus Bayview exceeds the capacity of Bayview, plus Humber, the existing capacity, and I see a problem here with Bayview right now.
Q. Okay. So when -
MR. DELANEY:

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A. Let me just -
Q. - when I see the Bayview 3, 4 and 5 T1, voltage 12.47 kilovolts, rating 15/20, existing 45, and then I go peak 19.9, 22, 25.9 and so on, with this XFMR maximum utility 62 percent, so -
MR. DELANEY:
A. You've got to--if we can look at note number 3, the existing capacity at Bayview at 45 assumes an additional 25 MVa unit is there.
Q. Okay.
MR. DELANEY:
A. Okay. So -
Q. So it would be without that additional unit 20?
MR. DELANEY:
A. Right now, as we speak today, Bayview is 20.
Q. So this five-year forecast includes this additional one already into it?
MR. DELANEY:
A. Exactly, yes.
Q. Okay. And so the Bayview one will be topped out according to your forecast for 2003 to 2008 based on the 20?
MR. DELANEY:

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A. As well, yes.
Q. All right.
MR. DELANEY:
A. Bayview has existing capacity of 20 and it will be 22 in 2003. So it's peaked out as well.
Q. So have we--has the same thing applied for Humber, Walbourne's and Walbourne's, Walbourne's T1 and Walbourne's T2, do they have in them devices proposed, new transformer capacity already proposed into this?
MR. DELANEY:
A. When we looked at the alternatives, and there are a number of alternatives to look at in configuring this system for the least cost going into the future, and the report goes into this in enormous detail as to the different configurations of the system to get at least cost. We've determined that the least cost alternative is to install the new unit at Walbourne's. I better get this right. And move--I get these two substations confused. Let's go back to Volume 1 here.
MR. MYLES:
Q. Page 30.

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MR. KENNEDY:
Q. Page 30.
MR. DELANEY:
A. Page 30, yes. So yes, the project that came out as least cost to accommodate the long range, the long term needs of Corner Brook in a least cost manner, is the installation of a new 25 MVa substation transformer at Walbourne's as a replacement for the existing 15 MVa transformer, and then moving that existing 15 MVa transformer at Walbourne's to Bayview sub. So this chart has the new capacity in it.
Q. In all cases, so this chart that we were looking at, that's up on the screen there now, that has the additional capacity for Walbourne's as well?
MR. DELANEY:
A. It has the additional capacity shown in Bayview actually.
Q. Additional capacity in Bayview. But the Walbourne's, are they the existing capacity?
MR. DELANEY:
A. Yes. To look at the existing situation, let's look at the current, the capacity rating.

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Q. Capacity rating, yes.
MR. DELANEY:
A. And right now in Bayview, we have 20 MVa.
Q. Right.
MR. DELANEY:
A. By 15/20 that means that the unit is 15 without the transformer radiators. With the radiators, it's 20.
Q. Okay.
MR. DELANEY:
A. And in Walbourne's, we have 15/20 as well.
Q. Okay. So when it says "existing" then though, the capacity MVa existing, and I got 45 there, that's not actually what's existing then? Existing is less than the 45?
MR. DELANEY:
A. The existing actually adds up to--there may be something missing in this chart, but the existing actually adds up, if memory serves me correct, to somewhere above 60, 63. I'm just trying to rationalize the chart here.
MR. LUDLOW:
A. Mr. Kennedy, if I may?
Q. Yes.
MR. LUDLOW:

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A. Is your question in the table as presented, is the existing under capacity MVa the--if we were to visit Walbourne's today, is that what we'd find?
MR. KENNEDY:
Q. Exactly.
MR. LUDLOW:
A. Okay.
Q. And Bayview.
MR. LUDLOW:
A. And Bayview. Well, it's definitely, by my understanding, that the--as per note 3 on the bottom -
Q. Right.
MR. LUDLOW:
A. - it is showing an increased additional transformer capacity at Bayview. I personally don't know what's in Bayview today, but I do know that in 2004, this chart includes that. So whether that's in that column or not, I don't know.
Q. Yes.
MR. LUDLOW:
A. I can certainly have a check.
MR. DELANEY:

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A. I can have a check. I know that the total combined capacity right now, as we sit, for Bayview, Humber and Walbourne's, those three substations that are interconnected that serves the City of Corner Brook, I know that the total combined capacity is less than the peak demand we're expecting there this winter. Now how this adds up exactly on the chart, I'm not sure right now, but that is a true statement.
Q. Okay. And the difficulty is your chart -
MR. DELANEY:
A. Shows some additional capacity.
Q. Well, some of it--it says existing, but it's actually existing with the proposed in some cases and -
MR. LUDLOW:
A. It's this whole premise of this proposal, Mr. Chairman, was driven on the premises Mr. Delaney just outlined. We have been moving the load between feeders. We've been optimizing the installed capacity and we're running up against a brick wall in that the installed transformation capacity is not capable of carrying the peak. So I think we

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MR. LUDLOW:
can get this straightened away on the table, but we're coming up against a wall on that transformation capacity of MVa installed and that's the point we're trying to put forward in our presentation. Obviously, we haven't done it too well.
Q. Okay.
MR. DELANEY:
A. And it gets very, very complicated when you get down to analysing the minutia of these numbers. If you look at note 4 and 5, we're talking about transferring 3 MVa from Walbourne's to a Bayview, and in 2007, another 1 MVa from a Walbourne's to a Bayview. So there are lots of permeations and commutations of how this data can be presented. The essential fact is that the peak capacity of all those transformers, what those transformers are rated for, the amount of load that all of them combined will be less than the peak load that we expect there this winter.
Q. Okay. I've got one more question, just to wade in on this. If you look at the Bayview

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figures and the forecasted undiversified peak for the period 2002 to 2008, it shows a fairly, you know, dramatic increase. It goes from 19.9 MVa to 27.9 MVa by 2008.
MR. DELANEY:
A. Yes.
Q. Okay. If I look at Walbourne's, it goes from a peak forecast in 2002 of 15 up to 16.6 forecasted for 2003 and then it starts declining, going back down to 14 MVa the very next year. So is there reason why the load on Walbourne's would be decreasing, why the load on Bayview is increasing, if these are all interconnected as you say?
MR. DELANEY:
A. Yes. The answer to that is in note 4 and note 5. It's load transfers being done from Walbourne's to Bayview which would have the effect of decreasing the load in Walbourne's and increasing the load in Bayview.
Q. And that's to--okay. All right. Okay. I wonder if we could talk about reliability for a bit, and if we could start with PUB-9. Okay, these are a list as per the question of projects being justified on the basis of

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reliability, and they're divided up between system wide, distribution, transmission and substation. Okay. Now I wonder if we could just look at PUB No. 8, and PUB-8 provided the SAIDI and SAIFI targets for 2003, but it's indicated that the Company does not set up time targets based on system wide, distribution, transmission, feeders or substation. The lawyer in me, does that mean that the Company does set up SAIDI and SAIFI targets based on system wide, distribution, transmission, feeders and substations?
(11:18 a.m.)
MR. LUDLOW:
A. I'm debating between a lawyer and an engineer here. What we set, maybe that would clarify it for you, Mr. Kennedy and Mr. Chairman, is that the SAIDI and SAIFI, as presented, is done on an annual basis and we have not set by transmission or by substation an individualized target. This is a corporate system wide duration and frequency index. The up time, as it's referred to in your question, is a simple reverse of downtime, is where I would go on that one. And the other thing in

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these numbers is these are what the customer sees, and by that, that includes everything from loss of supply to equipment failure to weather and so on, and so on, and so on. So that is a true reflection of what you, the customer, would see. But it's a global index. That is not a specific--you may have 100 percent. I may have much less reliability.
Q. So the system wide reliability target for 2003 is 4.75 SAIDI and 4.56 SAIFI?
MR. LUDLOW:
A. That is correct.
Q. Do you break that down to have a separate SAIDI and SAIFI target for distribution?
MR. LUDLOW:
A. We monitor where we are and monitor it against past performance, but I have not, as of to date, set targets strictly on distribution.
Q. Now it's indicated the company has not established reliability targets for the 2004 through to 2008 period. Reliability indices SAIDI and SAIFI are used in your short-term incentive program, correct?
MR. LUDLOW:
A. Yes, they are.

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MR. KENNEDY:
Q. And so you would need to set reliability targets for the use of your short-term incentive program for 2004?
MR. LUDLOW:
A. Yes, they would be.
Q. And when would they be set?
MR. LUDLOW:
A. They would be presented, if my memory serves me right, either in the fall--I think it's the fall, in October, early November.
Q. Okay.
MR. LUDLOW:
A. At the same time that the customer service and the operating expense reduction and other fundamental targets, including safety and so on, are set as well.
Q. Sure, okay. Now there was--if we could go to PUB-147. Okay, 147 was--the question asked "what were the SAIDI and SAIFI targets for 2000, 2001 and 2002?" and so, we can add the 2003 target to that. The SAIFI 2003 target was 4.56, the same as 2002, and the SAIDI 2003 target was 4.75, a decrease from the 2002 target of 5.85, correct?

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MR. LUDLOW:
A. Yes, that is correct.
Q. Okay. If we just go to PUB-148, and then these were the actual SAIDI and SAIFI measures for each of 2000, 2001 and 2002. So in the case of 2000, the target was 6.5 SAIFI and you achieved 4.93. So you exceeded your SAIFI target for that year?
MR. LUDLOW:
A. That is correct.
Q. You also exceeded your SAIDI target for that year. The target was 9.60 and you achieved 5.93?
MR. LUDLOW:
A. That is correct.
Q. Okay. The target for 2001 was a SAIFI of 5. 3 and you exceeded that. You had a SAIFI of 3.99?
MR. LUDLOW:
A. That is correct.
Q. I guess when I say exceeded -
MR. LUDLOW:
A. Well, hey, we did a good job that year.
Q. - you achieved a lower SAIFI, I guess, instead of exceeded. The target for SAIDI for 2001

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was 7.2 and you achieved a SAIDI of 3.73, so you exceeded the target that year?
MR. LUDLOW:
A. That's correct.
Q. And the next SAIFI was 4.56 target and you achieved 4.76, so slightly missed the target.
MR. LUDLOW:
A. Well, we missed the target.
Q. And SAIDI target was 5.85 and you achieved 4.54 so you bet your SAIDI target?
MR. LUDLOW:
A. That's correct.
Q. Okay. And the target for 2003 is the same SAIFI target as 2002 again?
MR. LUDLOW:
A. Yes, that is.
Q. Okay. And the target for SAIDI for 2003 is higher than what was achieved in SAIDI for 2002?
MR. LUDLOW:
A. That's correct.
Q. Okay. Now if we could go to PUB-13 and PUB-14. Okay, the question in PUB-13 asked "what evidence does Newfoundland Power have to support the proposition that its general

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service customers are not satisfied with the current level or reliability in their electrical service?" And you referenced the Customer Service Survey conducted in June 2003 where general service customers ranked reliability as one of the most important attributes and 13 percent of your general service customers indicated that reliability of electrical supply needed some improvement. And then PUB-14 is the reply concerning the residential customers and the figure there given is 20 percent, correct?
MR. LUDLOW:
A. That's correct.
Q. Okay. Now, I wonder if we could go to PUB-150.
MR. LUDLOW:
A. I need a bigger table.
Q. And we can look to Attachment A, and I just want to look at Question 31. This is the Customer Survey, the actual form used by the people conducting your customer surveys, correct, Mr. Ludlow?
MR. LUDLOW:
A. This is the actual survey, Mr. Chair, yes.

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MR. KENNEDY:
Q. Okay. And question 31 was the question relating to the gathering of information about the reliability of the power supply, and you've got "the power supply is reliable" and then you ask people to agree or disagree and they've got the choices there, and you ask "how much improvement, if any, is needed in that area?" and then they have a choice, none, a little, a lot, don't know, not applicable. Okay? All right. Just wanted to set up what the question was before we actually looked at the data. If we could look to Attachment F.
MR. LUDLOW:
A. Okay.
Q. And under "Customer Research" there's one--they're not numbered, these pages, so you'll have to just skim through. One is called "How well we are doing". Here we go. Okay, and as stated in the first bullet, the graph represents the percentage of customers who either strongly agree or somewhat agree with the statement, and the power is reliable; among your commercials, I don't know what that would work out to, about 97 percent?

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MR. LUDLOW:
A. Approximately.
Q. Agree or strongly agree or somewhat agree that your power is reliable and about 96 percent of your residential customers strongly agree or somewhat agree that your power is reliable?
MR. LUDLOW:
A. That is correct.
Q. Okay, and if we could go to--it might be the next one, "How can we improve?" There you go. And we've got it split between residential customers and commercial customers and the last bar graph there is "Reliability" and the blue is none, the purple is a little and the yellow is a lot. Would you agree with me that based on this chart at least, it would seem that the vast majority of your residential customers would see that the reliability is fine as it is, or could do with a little bit of improvement, I mean, it would seem to imply almost 98 percent of your residential customers would fall into one of those two groups.
MR. LUDLOW:
A. I think your assumption of the chart is

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accurate in that that's where the 17 and 20 percent is coming from in the previous questions we referred to; however, keep in mind that this is a global customer satisfaction survey representing 800 customers at this point in time. If we were in the, say, 80 percent that there was a lot of work required, we would have substantive change required to the electrical system of our province. Keep in mind where I'm going, in that this survey is conducted, it is done on a sampling base. There's 800 residentials and 400 commercial customers done through a group called, I believe is Telelink and that's subject to check, but it is a third party. What we have done, I'm quite pleased with these results, I might add, Mr. Chairman. I will say though that if we were to survey and this was a question actually put to me by Board staff at a technical conference, the performance on the Walbourne's feeders within the last two years as a result of a loss of supply issue and under frequency and load dropping, all in respect to the way we operate our system, that would not be reflected. The

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customers on the Wesleyville 02 project, which is here today, have already experienced an outage in the area of eight times the corporate statistic which we're running in the first six months. So, this satisfaction index is presented and has been used as a trend indicator overall on the Company. That's the reason we then further investigate at, what I would call the subset level, at feeder level and what have you, and that's the reason we haven't gone global in total overhaul of the electrical system, rather pinpoint it in, I've used the term "rifle shotted our approach" at specific trouble spots.
Q. Okay, but the bullet underneath makes some comments about residential customers who felt that a lot of improvements were needed identified these as required in meter reading accuracy, than community involvement. And then it goes, "Commercial customers who felt a lot of improvements were needed, said this is most often in relation to meter reading accuracy than community involvement." So it seems to note that, if I could say so, not a great scramble on either part to see a lot of

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MR. KENNEDY:
improvement in reliability.
MR. LUDLOW:
A. Well, I think as an extension what the observation here tells us is that we have sampled 800 Domestic customers. I've got 300 feeders running out there. At the best, if there was three on the Wesleyville 02 contact, as an example, I'll just use that as an example, that in turn will not sway these results in totality. This is telling us that their system on the Province of Newfoundland, on the Island, in totality is running in reasonable shape. That's what it is telling us. What it is not telling us that as you look at this system, that there are not weak spots and trouble spots that require addressing. That is not what this tool is for.
Q. No, this is just giving you a blanket view of statistically accurate supposed survey of your customer group and how they feel about reliability, correct?
MR. LUDLOW:
A. That's true.

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Q. But depending on what customer you ask, they may not have the same view on an individual basis?
MR. LUDLOW:
A. This was also addressed actually on a regular basis, gets addressed in several council chambers around this province. And the reason that we've addressed in several council chambers is not because the lights are on, it's usually because the lights are off. Lumsden being a key point, already this year, after multiple outages, one was 24 hours plus over the Christmas season. We had another one that happened a short while ago in June, I do believe, it was 20 hours. The point I am making here is that may never show up in this survey. I've sat in those chambers myself in those areas, I've been in Trepassey, I've been in Port aux Basques, I've met with Mayor Stein in Stephenville, as an example, in the past. That basically may never show up in this type of a document, but when you then take your past performance, assess why the performance, all these under-performing feeders, as we've presented, is there something we should do

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either in the operating accounts or in the capital accounts to address the under performance, I think it's paramount for us to move forward and try to address and improve on those situations. That's the basis that we use this document. If there's a global issue, community effort, advertising, those types of things, you would see it show up. Reliability, I'm quite proud of that number, to be quite honest with you. So that's the kind of piece we do.
Q. Okay, I think it's indicated though in some of your replies, Mr. Ludlow, that the Company has no reliability target, for instance, on what specific gains they hope to achieve through their re-built substation projects, correct?
MR. LUDLOW:
A. That is correct.
Q. And that you have not quantified any specific gains on reliability resulting from any of the capital expenditures that you've made in the past on rebuilding substations for 1992 to 2002, for instance?
(11:35 a.m.)
MR. LUDLOW:

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A. Well let me just, if I may, address that one for you, Mr. Chairman. A substation equipment, if we're dealing with power transformers or breakers, and I'm going to go back to the analogy I used yesterday of running that equipment to failure is not the way to run the business. That's where we bring in the information technology and the ability to assess and optimize when that life of equipment is nearing the time, you got to get it out. Last year, we lost two--three power transformers, one in Burin; we lost our portable in Burin and we lost one in Port aux Basques. Subsequently and just before that, we had started what we referred to as a predictive oil sampling process. Things that aren't showing up in this capital budget are three power transformers that we have found, repaired and never be seen in the general public as performing outages or capital expenditures. We've changed our attack from a calendar base maintenance program to moving more of scientific analysis based. That's where we then tied back into the information systems that help us drive these projects. So

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MR. LUDLOW:
by using that, I won't show an improvement in reliability because I won't let the reliability fall. That's not a matter--the other alternative to that was I've got a tap changer on a power transformer that's failing. Get a new one. Sorry, that's not the way we've been running. We basically will go in, try and identify and repair before catastrophic failure. And these things just don't fail and stop working. They can explode and we've got all the other issues coming with them. So that's, Mr. Kennedy, you may not see and you won't see an improvement in power system reliability as a result of a concrete pad being put under a breaker in Salt Pond. It won't show it because this is not all tied strictly to reliability. This is prudent engineering judgment and operation of a power utility, minimizing the cost and capital expenditures is our objective as we go forward.

Q. Okay, but I thought we established at the start that, for instance, we looked at PUB-9 and they were the projects that were justified

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under the basis of if we were going to improve reliability, correct?

MR. LUDLOW:

A. Where? Take me again.

Q. That's the principle justification, PUB-9. Table 1 provides a summary of all projects in the 2004 capital budget whose principle justification is based on improvements in reliability. So that's what we need to measure it against, presumably?

MR. LUDLOW:

A. Measure it against, you may have to prove the negative. And by that, what I'm saying is how do I show that a power transformer that didn't fail did not cause reliability to decrease.

Q. Okay, but that's different than saying maintaining reliability as opposed to improving reliability.

MR. LUDLOW:

A. That's a fair statement, fair statement.

Q. Right. And your safety target for 2003 is the same as your actual safety achieved in 2002, but there was nothing in the target set which would indicate that there was a required improvement in reliability.

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MR. LUDLOW:

A. Must be careful on those targets as well, those targets are not--I'm going to use the word that has been used here several time this morning, "normalized". These targets include safety in particular and a duration in which we're able to impact a loss of supply issue, it includes storms. A lot of utilities, as a matter of fact, the majority of utilities in Canada normalize these out. We will not normalize them out. So hence, my ability to work with Newfoundland and Labrador Hydro, which I might add has been, there's been the URSC committee we've been working on, the Inter-utility Reliability Standing Committee, has been working quite well on these types of topics. So, to say that we should include another factor on top of what's there, I think is inappropriate. These are calculated on running three year averages is the way these are done. We run them on three years and that way, that takes in, if I had, like last year was 17 trips, I've got 17 trips I've got to deal with this year, it's in my average. If I had none last year, my average is decreased or

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suppressed. So I do not set these averages based on, well, this is too high or that's too low.

Q. Okay, just so we're clear, you do not set individual reliability targets on anything other than your system wide infrastructure?

MR. LUDLOW:

A. That's fair.

Q. Okay, you do not go back and do an analysis to necessarily see what reliability increased or decrease reliability you may have achieved by virtue of past capital expenditures?

MR. LUDLOW:

A. Not totally correct. What we would do and we have done and presented in past budget filings, we have in fact tracked every distribution feeder upgrade on the five-year average leading into the project, and then, if my memory serves right, in the last year's budget there was a table presented that provided the subsequent year's performance back against the previous average. But strictly speaking, do I complete that project and say I expect a 70 percent reduction in SAIDI? No. But I do monitor and I will

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MR. LUDLOW:
readjust my capital budgets on a go-forward basis and the approach, alternative evaluation, construction standards and so on, depending upon past successes or the opposites.
Q. Okay, a couple of more questions and that will be it for this. If we could just look at NLH-62, because I figured I'd just be fair here on where I'm getting this statement from. This was the question concerning there were three reconfigured feeders and it was what is the predicted reliability of the three reconfigured feeders and how does it compare to the Company average. And it said, "Newfoundland Power has not predicted the reliability of the three reconfigured feeders and therefore, cannot compare it to the Company average."
MR. LUDLOW:
A. Okay, I just need to know where this reference is, so I need to get my book.
Q. Volume 3, Distribution. Appendix 3, Attachment B, it's the Pulpit Rock substation. I imagine the three feeders would be under

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just Appendix 3, which is the Lumsden, Cape Freels, Bay Roberts, Port de Grave and install new feeder, PUL 03, unless that's referring to the three--I believe in the Pulpit Rock you have two there now, you're adding a third?
MR. DELANEY:
A. Yes, that's what is occurring there. Right now, the Pulpit Rock substation serves the communities of Torbay, Flatrock, Bauline, Pouch Cove and that area. And the configuration of the system as it stands right now, is that there are two feeders, so if--the customers, I'm not entirely sure how they split there, but let's take for instance they split fifty/fifty the number of customers. If you were to have an outage on one of the feeders and that would affect fifty percent of the customers. The proposal here is to bring out an additional feeder and to split the load three ways, rather than two ways. And that will improve the reliability of the system, I think just as a physical reality, it will improve reliability because you have now three subsets, rather than two subsets. And the question here, of course, asked did we predict

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the reliability, and the answer was no, we did not specifically predict what the reliability improvement would be of the three feeders, verses the two.
Q. I guess that begs the question why not? Why wouldn't you conduct that analysis of after we do this work, what result do we expect?
MR. LUDLOW:
A. Well really I'm not even convinced of the value of it, to be quite honest with you. If we have assessed and determined, sorry, Mr. Chairman, that we have a problem in the Pouch Cove through to Torbay, up as far as the old airport, which is also one of the fastest growing areas in the east end, which is not the entire reason, the reason it's being done is reliability, okay. We have got problems in that area, that's the premise. Now, we know that area has been prone to issues, prone to problems and it's grown. You put all that together, would I go or not go if I could get a nine, verses a 10 percent improvement in the reliability? That is not the whole basis. We know we can improve. What it is, I am not able to predict it, physically I am not able

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to do it. I've attempted, by the way, but I can't do it.
Q. All right, but just go to page 4 of the report that we have up on the screen though. There was an analysis conducted and it's reliability implications and it's a study showing the relationship between total feeder length and then the outage statistic expressed as a SAIDI?
MR. LUDLOW:
A. It's a little more complicated than straight average.
Q. Yeah, fair enough. And this will be one I'm sure the statisticians would crunch and lots of deltas this and deltas that, but we end up with a trend line which shows that the longer the feeder, the more incidence you're going to have of interruptions and in this case, expresses duration index, correct?
MR. LUDLOW:
A. Correct.
Q. So that the whole purpose of putting another feeder in place is you're potentially shortening the feeder length, is that correct?

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MR. LUDLOW:
A. That's in effect the impact. What we're doing here, if this here shows an analysis of--or a correlation between duration of outage and length of feeder.
Q. Right.
MR. LUDLOW:
A. Now, in my brain that tells me that should be a pretty, well that's pretty commonsense. But it doesn't tell me that I'm going to be pushing out feeders or additional feeders or capacity in all my long feeders. Okay? Now, we here, in this case, have a long feeder, a densely populated feeder in a growing area. You put all of those factors together, look at past performance, on the end also of a radial transmission system that is not one of the seven. And this is Torbay, by the way, we've got a strange name on the substation called Pulpit Rock, but that's where it is. Put all that together and that's the reason this is being presented.
Q. Okay, but if we go over to the next page, under the discussion and after looking at the various options, the third point there, you

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look at option two, you say that's the new substation, that's quite expensive. Option one and three will increase the capacity of the existing system and then you go, "Option 1 will reduce the length of the Pulpit Rock distribution feeders and consequently improve the reliability." So wouldn't you then, by virtue at least of this trend line and the data that you have, be able to predict by the introduction of this new feeder what improvement you should be able to achieve by virtue of its introduction into the system there?
MR. DELANEY:
A. I don't think so, because the length of feeder is just one of numerous variables that you would have to bring into any assumptions or calculations with respect to the reliability of a feeder, I would want to know as an engineer how many automatic sleeves are on that feeder, how many cut outs are on that feeder, how many transformers are there without lightening arresters, what's the size of the conductor, is it Number 2 AC or is it 4/0. There would just be a multitude of

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factors involved in taking together some statistical analysis of making some assumption as to how that's going to improve as a consequence of these actions. I just think it's a very difficult analysis to do.
(11:50 a.m.)
Q. One last question on this and that's PUB-149. The question was, if it's stated MP is not established for reliability targets for 2004 to 2008, how does Newfoundland Power decide where it should focus its efforts to improve reliability. And the second paragraph to your reply, "While Newfoundland Power has not set reliability targets for the 2004 through to 2008 period, we use reliability statistics to focus on geographical areas which over a five-year period experience worse than average service reliability". So, I've seen the--there's a feeder report and that goes through an analysis of the performance of different feeders and looks at what the causes were for outages and were they caused by extraordinary events like a storm, you discount that and so on, where it's unexplainable and the engineering review indicates that the line is

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just in a deteriorated state, then you make the decision to rehabilitate that line, correct?
MR. LUDLOW:
A. Correct.
Q. Okay, so that applies to feeders. Do you do the same review on then your other components of your system, substations, transmission?
MR. LUDLOW:
A. Okay. Let me start now and I'll hand off to Mr. Delaney. We take our system, I think we've gone through the generation portion fairly substantively in the engineering details. So, I'll leave that one for the time being. We move it up to transmission. Every year our transmission lines are patrolled with a detailed inspection and that's also further supplemented with throughout the year inspections of condition. And that can be from a sounding of the poles, to shelliness of the poles. We take conductor samples in specific areas if we've had conductor breaks and have these analyzed by laboratories. Examples of that would have been the 301 project where we had interior deterioration as

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MR. LUDLOW:
a result of salt and sulphur showed up. We have no idea where it comes from, but the brittleness of the conductor was being--sorry, the conductor was becoming brittle and less bendable is the word I'll use. That is an ongoing process. That will also include right-of-way conditions. We then do in our substations monthly inspections and that would be to check for safety and general operating procedures, the specific equipment is staged through a series of processes. And where I'll go with that would be, I'll take the oil base maintenance or the condition base maintenance as an example. Every year we will take and do take samples of oil in transformers to check its ability to express arc, are we getting contaminants, are we getting, you know, explosive gasses. We will also look at and investigate alternatives to its repair or removal. We will also look at radiators, all the various pieces of equipment on a regular predetermined basis, a transformer is overhauled, from paint to bushings to the internal workings of it. A breaker, for

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example, and the number escapes me, I will say 8 to 10 years is literally stripped down and overhauled. It's condition is assessed at that point. Prior to that you get different levels of investigation into the operation of the equipment. So, all through that period this is an ongoing condition assessment, you're looking at it, you're working it, you're maintaining, you're repairing it. You go to your transmission--I've done that one--go to distribution and what we're doing on that front is over five year period, we're taking 20 percent a year of our feeders to go through and literally walk underneath each pole, look for some things as simple as split cross-arms, a loose connector that's visible, certain things that these people are trained to look for, automatic sleeves, cut outs. PCB transformers or transformers that are oil filled, we have no PCB per se that we're finding. We may be finding some low level contaminations that we're working on. Insulators, wire, we will look at the wire. A trained eye can pick up a number 4 copper sitting in that insulator that's been there

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for 30 years that's now smaller than a pencil, it's worn. That then all comes back into the condition assessment. That is further aligned with, I'll look at history, historical performance. We will tie that back against what's happening in the industry. At a previous hearing we had a report where we talked in terms of the BI & I Report on power transformer failure rates that are being predicted in the foreseeable future. And it was interesting because last year I lost three. Now, what can I do to mitigate that? I don't necessarily want to change the transformers, but I certainly want to get in there, change my maintenance so I can work on it and head off the failures. That all goes in the pot of the capital program at the manager and departmental level and that's how we focus. That's how we got to Wesleyville. That's how we get to the various projects such as substations and radiators and what have you.

Q. I think you said you were going to let Mr. Delaney actually have a chance to talk.

MR. DELANEY:

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A. I don't know if there's much I can add to that.

Q. No, I wouldn't imagine.

MR. LUDLOW:

A. Sorry, boss.

Q. All right. Just for something completely different, what I'd like to do is just cover one last topic area. I think I may be finished with the Panel after that and it would be appropriate to take a break then anyways and then I'll be able to advise counsel whether we're set up for the IT once I just review my notes.

CHAIRMAN:

Q. Fine.

MR. KENNEDY:

Q. If that's okay, Chair.

CHAIRMAN:

Q. That's fine.

MR. KENNEDY:

Q. Thank you. And I presume you probably know what's coming, that's a dark skies question and I have some hard copies.

MR. MYLES:

Q. You're planning on calling these people to

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MR. MYLES:
testify, are you? I'll take that as a no.
MR. KENNEDY:
Q. Yes. Chair, these are two articles, they were provided to counsel for Newfoundland Power previously, a couple of day ago, so I think they hopefully brought this to the attention of their witnesses already.
MR. MYLES:
Q. That's correct, Mr. Chair.
MR. KENNEDY:
Q. And I guess we should label them Information Request Number 2, sorry, Information Item Number 2 and Information Item Number 3. Number 2 would be the New York Times article and Number 3 is the NASA article. And gentlemen it's indicated in one of the replies to an RFI, PUB-45 that Newfoundland Power has been aware of the dark skies initiative with respect to light pollution for some time, but that you have not adopted any policies in regards to the matter. Just for the sake of brevity, you've also indicated in PUB-46 that you use high pressure street lighting, high pressure bulbs in your street lighting and

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that in PUB-47 you indicated that you don't offer low pressure sodium lighting as an alternative to high pressure sodium lighting. I wonder if you could just comment on that first. Is there a reason why you don't employ the more energy efficient low pressure sodium bulbs.
MR. LUDLOW:
A. Okay. There's a couple of items, I guess. First of all, lighting and this is, I think, brought out in the two articles. There's a balance between cost and lighting, I think lumens or lux are the appropriate terms that's being used or candle powers, I'm not sure what it is these days, the ability of the light to provide the service required. We have not stocked or at this point, have any intention of stocking the low pressure sodium lighting fixture or bulb. The reason for that is, it is true, it is more energy efficient, it is also true that it provides a monochromatic light that also poses the reverse in that there are security concerns and your ability to distinguish between colours after dark as a result of the

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absorption rate of the light emitted.
Q. If you could put it in lay terms, the existing high pressure bulbs that you use give off a white greeny glow, the low pressure bulbs are known for giving off a more orange tinged light.
MR. LUDLOW:
A. Close. The mercury vapour that's referred gives a white or a really bright light. The high pressure is a yellow light. The low pressure sodium that's being referred to is on the lower end of yellow to orange.
Q. Okay. But as far as you're aware, the low pressure bulbs that are available on the marketplace, are they compatible with the existing cobra head lamps that you use in most of your street lighting?
MR. LUDLOW:
A. I have to back up and say here that although we have been aware of this, the--I have gone for twenty odd year in this business, it has been raised to my attention on, I would say, three occasions, the low pressure sodium. Once in 1994, I worked with low pressure sodium lighting in Prince Edward Island and a

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third time was by Board counsel. And when I brought this to the attention of our standards group, they were--how would I say--a little bit dumbfounded about the whole idea, not in a negative way, but it was not something that was top of mind. So, I want to clarify that this has not been a burning issue by our customers. As a matter of fact, the reverse, in my experience in PEI using low pressure, there have been concerns about the type of light.
Q. Sure. Now, in addition to the types of bulbs, there's also issues about the just the lighting design itself, correct.
MR. LUDLOW:
A. That is correct.
Q. Okay. And there's an example in the article, "The Fading Milky Way" which is at page 3 of the article showing the flat lens cobra head fixtures, instead of the ubiquitous drop lens cobra heads. Do you see that in the article?
MR. LUDLOW:
A. I do.
Q. And Newfoundland Power uses the ubiquitous drop lens cobra head luminary?

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MR. LUDLOW:

A. We've used both. We have, in fact, experimented or tried the flat lens cobra head with the high pressure bulb. It was amazing that this do produce a more focused light. Whereas the dropped head cobra head luminair has a tendency to disperse light and give more of a softer edge. And I guess after reading the articles and doing a little research, it also reflects some back up as well. The problems that we were receiving, Mr. Chairman, was that we were sending trucks because people thought the lights were out. They were so focused and the breadth on the roadways or that they were used to either mercury vapour or high pressure, we were using high pressure, but it was the direction of the light, if you can picture it. They, in fact--we would get calls, there's something wrong with the light, we're not getting the coverage that we would traditionally get here.

Q. That wouldn't be a reason though, would it, to not use the more light sensitive flat head fixtures?

MR. LUDLOW:

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A. Well, customer concerns or customer complaints would certainly drive or direct our attention as to how we proceed with these items.

MR. DELANEY:

A. There's one practical example that I've heard of, if you were to light a parking lot with low pressure sodium lights, you cannot tell the difference in the colours of the cars on the parking lot. So, I would suspect that that would be a concern to the RNC and some others.

Q. That's all the questions I have at this point, Chair.

CHAIRMAN:

Q. All right, thank you, Mr. Kennedy. I guess, it's 12:00, so we'll take the scheduled 15 minute recess and come back. Thank you.

(RECESS - 12:00 noon)

(RESUME - 12:28 p.m.)

CHAIRPERSON:

Q. Okay, Mr. Myles, I guess you perhaps have some questions for redirect.

MR. MYLES:

Q. Mr. Chairman, I have one question and one point. The point is that in reviewing the

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table, which is found as Appendix A in the Walbourne report, which is Volume 2, Substations Appendix 4, Attachment A, the Appendix A, I think at least one of those numbers is wrong, and what we plan on doing is filing a revised table for you in the morning. And I have one question, and it's for Mr. Ludlow. Mr. Ludlow, based upon the engineering and the testing that's been done to date with respect to the steel penstock at New Chelsea, can you advise the Board as to what alternatives are available to Newfoundland Power, other than replacement of the steel penstocks?

MR. LUDLOW:

A. Mr. Chairman, from our perspective, based upon all inputs, there are no alternatives other than to replace this penstock. The report, as we went through yesterday, did make a statement that there was anticipated to be ten to fifteen years of remaining life in the penstock, in the steel section. However, when the actual inspection, ultrasonic inspection was done, as well as the external visual inspections were completed, it became very

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clear that this was at the end of its useful life. Also, the point that was made very clear to me, was if any work were to proceed around the penstock and have it unearthed, the actual structural integrity of it being supported and so on under working conditions would be a real concern. Hence, the replacement that has been put forward.

MR. MYLES:

Q. Thank you, Mr. Ludlow. I have no further questions, Mr. Chairman.

CHAIRPERSON:

Q. Thank you, Mr. Myles. Commissioner Powell, do you have any questions?

COMMISSIONER POWELL:

Q. Thank you, Chair. I have a lot of questions. I don't know if I'm able to ask them all. I was told many years ago that most a person ever understood of any subject is five percent, and all you have to do is sit here, you realize how accurate that was. The Dark Skies initiative is the last thing counsel brought up. Has Newfoundland Power done any economic analysis to see if it was feasible to do it, what it would cost and what the

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COMMISSIONER POWELL:
potential saving would be, from a generation side?
MR. LUDLOW:
A. No, Commissioner Powell, we have not at this point in time completed any economics regarding the use of low pressure sodium. The point here that we did move though from a mercury vapour or the white light to the yellow light or the high pressure sodium in the last ten to fifteen years and are still in that change out process, and that was based upon lower energy consumption with the high pressure versus the mercury vapour. To go to the other step, to move it to the low pressure, as is raised by the Dark Skies group, and I'm not even sure they're 100 percent behind this area, it's the whole concept of light pollution is my understanding of it. One of the alternatives may be that end. We have not looked there, sir, and because there are security and safety issues as well.
Q. Do you have any data to show the savings going from the mercury to the high?

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MR. LUDLOW:
A. Yes, we do, and as a matter of fact, to give you an example, I'll lead and then you can fill, Phonse, if you would, is that a 150-watt mercury vapour light will throw off the same candle power as a 100-watt high pressure sodium light, and the wattage that I'm referring to is the energy consumption. So it is much more efficient to be using the high pressure sodium versus the mercury vapour. That's on the actual operating costs. The other side of that equation, Commissioner Powell, is the actual purchase cost of the light itself is different. It is not as simple a matter as changing a bulb in that, if I go back in my--a bulb, a mercury vapour bulb would be in the four to five dollar range. A high pressure sodium bulb is in the $25-30 range. So there's the operating side from the generating perspective and then you have the actual cost of the head and the maintenance or the purchase of the bulb. So that's some factors.
MR. DELANEY:
A. Just to add a little bit to it. The exact

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value that we've determined is that high pressure sodium saves about 37 percent of the energy for the same amount of light versus mercury vapour, and in the system now, there is about 54,000 street lights and 80 percent of them are high pressure sodium and 20 percent are mercury vapour.
Q. So there have been significant saving then, in terms of the amount of power that need to be generated to keep the street light going?
MR. DELANEY:
A. Yes. Over the years, from the move from mercury vapour to high pressure sodium.
Q. So this is the same calculation that you see the--trying to get homeowners to switch from the normal light bulb to the fluorescent light bulb and they say after seven years, or depends on which you believe, that they do have on the package some sort of an economic analysis of why I pay $8.00 for a bulb as opposed to getting three for $1.00.
MR. LUDLOW:
A. Pretty much the same scenario, Commissioner Powell, yes.
Q. But you have no indication if you drop down

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another level that the savings would be as high?
MR. LUDLOW:
A. This next step is broader than straight energy dollars, I guess is the point. We haven't gone there as of yet, and actually there are very few utilities that--matter of fact, I don't know of any utility in Canada that have gone with all low pressure. I referenced my work in Maritime Electric or in Prince Edward Island, I'm sorry. There, the roadways are owned or the lighting is owned by the Provincial government. It uses a low pressure sodium light. Now that's a--I'm going to--bear with me, I might be off a foot, but a 10 to 12 foot fluorescent tube type of fixture, you know, it's a long overhanging style because of the low start required to do this. That's a totally different head than the cobra head that counsel and I were discussing earlier. That has brought its difficulties in operating and management because we also ran that contract and handling a 10 or 12 foot fluorescent bulb on a line truck becomes a challenge, if you can picture it. UPEI has

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MR. LUDLOW:
also used the low pressure lighting, low pressure sodium lighting on some of their, I guess what do you call it, that ground lighting and those types of things. As late as yesterday, I did check with my counterpart at Maritime and his comment was there is some concern. Now whether that concern is with the difference in lighting, everybody with a change needless to say, that's not being negative, you know, to go from a bright yellow to a deeper yellow, that's a concern. And also, the focusing of the light and the colours and the security are also issues that have been raised, other than the straight economics.

Q. No thought then to sort of doing a public-- excuse me, a pilot project and informing the public what you're doing at such an area so they wouldn't be alarmed, assuming the lights were out when they're actually on? Because the highways now, you drive down, at least my part of the country, you get the feeling that different street lights give different light. There are times you, as you say, you think the

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street light is out but it's--that must be a different bulb you have in there?

MR. LUDLOW:

A. This may very well be the difference that I was explaining to Counsel Kennedy earlier. The difference between, I think the word is ubiquitous, the dropped head versus the flat head, where we referenced cobra-style lighting, and what it is, it's the piece that sticks out on the end of the steel arm, and where they're flat, the actual reflector of that light is up in the head, so there's a metal reflector pushing down which gives it very firm parameters, if you think about the lighting pattern. With the ubiquitous head, the reflector is up here, but there's a refractor in the glass, such that when the light hits the glass, it goes on a much broader scheme. That has ramifications from lighting design, from closeness of design in parking lots and those types of things as well. If we were designing a highway, just say the crosstown arterial, that would have impact on how close or how far away you would put your standards as well. So these are just

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factors that come in.

Q. So I have security lighting in my yard, compliments of Newfoundland Power, which I pay them a small fee, would I have a choice between wanting more focus as a broader, or do you have a standard one that you -

MR. LUDLOW:

A. Right now, in our inventory, we would basically carry one type of standard for that style of lighting and that most likely, if it's a yellow light, it's a 100-watt high pressure sodium light with a dropped reflector. We did have some of the flat type of glass, but we had to--we discontinued it is what happened. So we don't carry sort of a wide range of lighting, and that's another item that would come into play.

Q. Good. Thank you. I started with that one because the questions were in my head from the previous discussion. The one question I wanted to talk with you about is when I read the application and read all the evidence that was submitted, and then listening to the counsel for Hydro, I was left with the impression that, I don't have the figure here,

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but $6.9 million in energy off of your 50 odd billion dollar. I didn't get the impression that the communications with Hydro was there. I mean, Newfoundland Power is primary distributor of power, even though they have 23 various generation sites, but in the whole grid, it's a relatively small portion of it, and so the one on like Chelsea, we'll just use as an example, certainly detail in why it needs to be replaced and that, but my question was do you need to replace it, and do you really need to replace it that is the least cost, and I was interested in your discussion with Hydro in terms of least cost and not obviously the first dollar you see. There's so many dollars you have to look at, and I appreciate that. That's just good business management. But, am I right in assuming that Newfoundland Power developed the Chelsea project on their own because they felt that they needed to replace it without sitting down with Hydro and saying "do we need to? Do you have a better alternative for us?" In terms of energy to the grid and costs for the rate payers.

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MR. LUDLOW:

A. We would not, in the Chelsea project as an example, have sat down with Newfoundland and Labrador Hydro and discussed, how would I say, what we're doing or where we're going with respect to Chelsea. We would however be continuously discussing with Hydro on load forecasting, energy production and where we see, on an annual or, you know, throughout the year in system operations. So I certainly-- I'll come back to that point, Commissioner Powell, if I may, but I certainly wouldn't want to leave you with the impression that discussions between Newfoundland Power and Newfoundland Hydro are not occurring. They definitely are, on every aspect of operations, engineering, planning, outage management, standby generation. Even this summer, to give you an example, we were in discussions as late as July regarding the planning and outage management for next July's outage to the southwest coast when they are doing their work on 214, 214L which is a long radial. So I just wanted to make sure that's clear. There's a lot of work on that front. On the

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forecasting of energy production and load and energy purchase, that discussion we forward and discuss the load profiles on an annual basis with them, where we see loads growing, where we see things happening, and part of that would also be then our ability to generate. That's also part of that exercise. With respect to the economics of the project, that is something we have done in-house and have always done so. You know, it's not that we wouldn't talk to them about it. We just haven't.

Q. The issue of duplication is an issue, I guess, that came up with Newfoundland Power's General Rate Application. It came up at Hydro's rate application. It came up on the Capital Budget hearing. And the Board, in PUB-36 on Schedule C, Item 1X, as condition for future filings -

MR. LUDLOW:

A. I wouldn't have it.

Q. I'll read it.

MR. LUDLOW:

A. If you would.

(12:45 p.m.)

Q. 1X said "Newfoundland Power shall file future

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Capital Budget Applications in accordance with the following guidelines," and there's 13 or 12 of these listed. No. 9 is "a description and related documentation outlining the results of any discussions of the project that have taken place between the utilities in an effort to reduce expenditures by avoiding duplication of services or increased sharing of resources and expenses." So when I read that, the generation, and I said, you know, Hydro is the generator in the province, so therefore all your generation projects would have captured under that. And then, we talked about least cost and one of the things that there's been a lot of money spent by both utilities over the last number of years, at least applications came to have expenditures, was fairly sophisticated computer models, talking about the efficient use of the resources, the ability to look at sources of generation and running them at the optimum level. Holyrood, from my understanding, years ago it was just there for peaking. Now it's a basic part of our generation. The ability of this computer modelling, my understanding, was

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ability to be able to use Holyrood and essentially take it and get the efficiencies up.

So just like a car, you run around town and you get 10 miles to the gallon. You can run around the highway, you get 30 miles to the gallon and different engine configurations you can be able to optimize, depending on what you want it for. So some of the figures thrown in justification using $20 a barrel or $28 a barrel of oil, to me it didn't mean it was pertinent, because maybe if New Chelsea wasn't there Holyrood probably would be running for half an hour every day and therefore it mightn't cost any more oil because you're getting more efficient because you're running it longer. That's just a layman. So these are the sort of things that I would have thought that Newfoundland Power would have to get with Hydro and saying, you know, we have this generation. We've had it for 50 years. We're going to spend $4 million to refurbish it, but do we need to? Because would that not make your system more reliable or more efficient and therefore the need is

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not there.
MR. LUDLOW:
A. Two things, if I may start. I would agree with your premise that Newfoundland and Labrador Hydro is a generator. They are also responsible for the 230 Kv grid on the island. There's also, I think, how would I say, we are also a generator and have been for in excess of 100 years, and I just want to make that point.
Q. I realize that.
MR. LUDLOW:
A. And that's 23 small hydro are very valuable from low-cost energy production. So that's one piece I would put out to the table. Also I think it's important that on this island there are other generators in people. We have Deer Lake Power and also Abitibi Consolidated and there's a NUG in Rattle Brook, which the name escapes me.
The second point is that when we look at the cost of running New Chelsea, and we do our, and I'm saying our, extended costs through capital in keeping the systems going and everything else, and we're in the three

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and a half cent range, the last production facilities to come online on this island, it's my understanding, was in the five and a half plus range. So from a straight economics on that side, that should show, at least to our way of thinking, Commissioner Powell, that that's a very positive project.
Back to your point of generation, whether it's $20 a barrel or $28 a barrel or $32 a barrel, the fact is, as I would see it, is that if we produce X number of gigawatt hours of energy at Chelsea, it's going to come from somewhere and if it comes from--and it will eventually come from Holyrood, depending upon the time of the year and water usage, it will cost money to generate that energy. It's not so small that it'll run when the machine is shut down. The point I'm making, to generate energy will cost money. So to step back from where I'd sit, we basically run our hydro systems, but in full, constant communication with Newfoundland and Labrador Hydro. On their dispatch, for example, we can get a call today, all hydro on, all--whatever you got. Needless to say, if we don't have water, we

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can't run them. But that's the type of operations that are in place to minimize peak, to minimize the production. That conversation is happening continuously between our two utilities at the control centre level. So the dispatch of hydro, the dispatch of the gas turbines is not something that we do totally, how would I say, removed. That's like that with Newfoundland Hydro. So I'm not sure that that's clear in these discussions.
Q. That wasn't the--I appreciate that, and I take that as a given. My only question is that it's just like if I get in my car now and I drive down Elizabeth Avenue and I go two kilometres, Elizabeth Avenue is that long, or if I was up there on the arterial route and drive two kilometres, I have all the same costs, but I'll probably -
MR. LUDLOW:
A. That's fair.
Q. - only have to burn half a gallon or litre of gas to do it, as opposed to going down there. So I'm saying it's more efficient. I mean, for the same litre of gas, I can probably go four kilometres on the arterial route, but the

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maximum, if I hit all the lights on Elizabeth Avenue, I'm only going to get -
MR. LUDLOW:
A. Fair assessment in the operating efficient--sorry.
Q. Yes. So that's where I'm saying the question--when I looked at New Chelsea, it's not that the costs are reasonable or anything else like that, but given the total thing, do we need it, at this point in time. And so that's where the experts at Hydro are saying, "gee, put this in our equation. We'll run this through," and maybe we'd eliminate a bunch of street lights because we know now, with our computer models, we should only be running--and that's what's missing. That's what I said--and I thought that's what we were trying to capture in PUB-36 in Schedule C was that little nub that there. It's an irritant as much as anything else, but you think that that needs to be done.
MR. LUDLOW:
A. When you look at the size, the relative sizes of these plants, your point is well taken regarding operating efficient ranges, and I

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MR. LUDLOW:
think that's the -
Q. Yes.
MR. LUDLOW:
A. - and I think that's the--you get in a range-- I'm not--I can't talk to you about Holyrood. I don't know the details of the operating, but I do know the fundamentals of operating efficiencies for thermal plants. I agree with what you're saying. Subject to check, if a unit is on 150 megawatts at Holyrood, we're talking approximately, I got 3.7 in my mind or 4 megawatts is what we're saying here. Now that little piece, in relative sizing, is huge differences, and I fully acknowledge your point. When we looked at this project, I wouldn't use the term 'permission' but discussion, I guess, with Hydro, we have taken as a given that any energy source that can produce energy at an operating rate of .5 cents to .6 cents a kilowatt hour, that's outside the capital side, which is rough range, this one would be about .6 cents, that has been functioning and running, would make solid future long-giving benefit to the

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customers of our province. And I know I'm walking around your point, because I don't have the exact point on the efficiency ranges.
Q. Yes, because one of the things that's happening, and I think you sort of told us in different things is that no question a lot of your plants, they're older plants. The cost in today's terms, today's dollars, are peanuts. But as you're going, putting more and more money into them, real dollars, and if you had to rebuild them all, the cost of the energy would be significantly higher per kilowatt.
MR. LUDLOW:
A. That's fair.
Q. And the figure you just quoted earlier, there's no reason to think that they would be the same costs for Newfoundland Power that would be for me. So I guess the thing that I'm saying is, okay, we know they're going to fail eventually or we have to rebuild them. Let's not nickel and dime ourselves to death. Maybe we should look at maybe they serve as well, but they're just not the way we want to go in the future, and you get into total cost,

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as you say, and you got to look at the whole ball of wax, everything from the ongoing environmental problems to the actual cost of buying barrels of oil, and I just get the feeling that that wasn't in the mix.
MR. LUDLOW:
A. I think your observation is pretty much accurate in that on an individual plant basis, Commissioner Powell. However, on the mix between our available Hydro production facilities is certainly built into the long haul estimates of when additional capacity is required for this island as well as energy dispatch and so on. That was the point I was coming to earlier. So if there is a--you know, the $4 million expenditure at New Chelsea, okay, for 3.7 or 3.8 megawatt plant, to rebuild that would run us, I would estimate, in the 15-16, maybe even 18 million dollar range. So to forego the opportunity and shut it down, which was one of the options I looked at a plant a while ago and again, before--I have one or two plants now that when they get to the stage that Chelsea's at, personally I'm going to have an awful hard

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time justifying sitting in this seat. I know I'm at the smaller picture versus the bigger picture, but I'm trying to give you the flavour that the overall system is run as a system. Now whether or not the financial gurus sit down and go through all of the details and crunch the numbers, the energy cost, the investment point, and we do have a substantive investment in Chelsea that has served us well for the last, you know, 60 (sic.) years. So maybe I'm not answering, but I'm doing the best I can with it.
Q. No, no, I appreciate, you're just a humble engineer and -
MR. LUDLOW:
A. Thank you, sir.
Q. I know there's people coming behind you that-- we're always giving you fellows a hard time. But, that leads me into another question about that, that threw me off and I'll throw it at you and I'm sure somebody else will answer it later on. Just bear with me for a moment there, I flagged it. Yes. P.U.B. 124 we talked about--there was a question there about New Chelsea, and they asked about the

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COMMISSIONER POWELL:
levelized cost for kilowatt power produced and various things. But, that--and some figures thrown at me. But it said in brackets, "(This number does not include any carrying charges from the existing plant as those are sunk costs)." And I appreciate that there would be because, you know, the idea of something being totally written off or replaced, I mean, that's utopia, that's in an accountant's dreamland or something. But I went--then I had no problem with that until I read the next one, P.U.B. 125, and the question was, "What is the current un-depreciated capital costs in the New Chelsea plant?" And then it says, "The Company does not maintain a record of un-depreciated capital costs of each hydro plant." So, I went back to 124. How could they answer that and say there was some costs and you have no record of them?

MR. LUDLOW:
A. I don't often do this Commissioner Powell, but this is one I am going to have to bow out on.
Q. Yeah, okay. No, but -

MR. LUDLOW:

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A. I'm sorry.
Q. Then it goes back to me. I realize you're crunching numbers, you're doing it in, you know, in your best effort. And I have no doubts about it. Matter of fact, I should compliment you on the detail that probably gets you in trouble, in a sense. I mean, it's a very good presentation. But I'm sometimes wondering, are you working with the right numbers. I mean, you know, because you have to go back and rely on various things, for somebody to crunched the numbers to you and say what's this cost in kilowatt, because this is what needs to be done, from an engineering point of view -

MR. LUDLOW:
A. Very much so.
Q. - there's no questions that's what needs to be done. Somebody else got to tell you whether the economics are there, I mean, in terms of-- so, I'm just left with saying, okay, how can you have it in saying there are some costs. And I have no doubts there probably are, but then an operation like Newfoundland Power, and we'll talk about it later on, with all the

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money spent on computers and that, they don't know what individual things sort of cost, you know, sort of -

(1:00 p.m.)

MR. LUDLOW:
A. Well, it's an interesting piece because--I will try as an engineer veering into your realm of expertise, and that's dangerous at the best of times, Commissioner Powell, I'm sure. From the depreciation of hydro plant assets, as I understand it, is grouped into one big group with the 23 or 24--23 plants in there. And that is depreciated over as per whatever. I think the reference that you're referring to is that there are some costs. Whether they can be quantified is the question. And when I read that answer and read it before, I don't think we're in a position to quantify it. Although we may have computer systems today, a lot of these computer systems are ten years old. And, I mean, I don't know how far back. I mean, these assets depreciate over, what, 40 years, I guess, 30, 40, years.
Q. Um-hm.

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MR. LUDLOW:
A. If we were to go back and try and recapture all those costs and how that breaks down, I'm in over my waders, Commissioner.
Q. Oh, no, I know what you're saying. Somebody at sometime make that judgment and we, we have so much into the system and these costs are dead now. We'll talk to, when we get to your financial people, how that's handled from an accounting point-of-view, is it's a cost. But then I just get looking at the figure. You're talking about kilowatt, and I go back to Hydro and they say, oh, yeah, if that power wasn't there, we could run Holyrood and get that extra miles to the gallon and therefore our cost would be there. Trying to get the apples and apples together and let's throw out the oranges and the grapefruits sort of thing. And I--that's what I--you know, again, it's not--from where you sit, I have no problem. But I'm just wondering with--like all the players are not at the table, sort of thing, that's the impression I'm getting here, and -

MR. LUDLOW:
A. Well, you know, I'm not here and I'm sorry, I

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MR. LUDLOW:
can't defend Hydro. But I will say that I returned to this business in 1997 and when we talk about cooperation between the two businesses, I keep coming back to that point because there's an error that there's not the cooperation. Let's be careful between duplication and cooperation, there's a fundamental difference.
Q. Um-hm.
MR. LUDLOW:
A. And, you know, right down to line crews being called, to construction projects in St. Patrick's and I mentioned--that's not a shopping list I'm reading from. These are day to day. For example, the lightening arrester failure on Christmas day here, the loss of their EMS system, I mean, we're involved in those types of things through discussions, we're updated immediately as to where things are. The offer goes out to help, sometimes it's taken, sometimes it's not. Sometimes we'll ask, sometimes they'll offer, sometimes they won't. But that to me is true cooperation between two public utilities. You

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know, there's equipment sharing out there. So that's the reason why you say it's not all together, it may not appear on that energy side to be the case, but I certainly wouldn't want it to go broader. Back to the numbers -
Q. I'm not suggesting--you know, I have no doubts on a day-to-day basis the vast majority of personnel in and around Hydro and Newfoundland Power. I mean, they're in the common business and they have a lot of things to share, no question about that. One other thing on the generation side, it sort of struck me on the reading the attachment on the Morris plant turbine and stationary steel inspection, let me just read it and you probably got the answer. It just struck me as--they talked about the assessment of the turbine inspection. And it said the turbine was opened up and inspected and was found that the stationary steels in this turbine were mild carbon steel and not type 410 stainless steel. And what struck me as funny, and I made a note of it, why were you surprised? I mean, don't you know what's inside your equipment you got? It sort of struck me, I said, okay.

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MR. LUDLOW:
A. When you read it, I sort of anticipated where your question was coming from.
MR. DELANEY:
A. I think it may have to do with the person who wrote the report.
Q. Okay.
MR. DELANEY:
A. Being a surprise.
Q. Okay. Must be an accountant who wrote the report.
MR. DELANEY:
A. I think it was an engineer. You know, we have the different--the stainless steel inside the runners and this was a mild carbon steel and I guess I can't testify as to his amount of surprise, but I guess he didn't expect to see it there. And, you know, other than that -
Q. Because this goes back to other questions you talked about. And I appreciate this. The challenge is to anticipate. It's just like you're running a car, I mean, I don't want my car in the garage if I'm--or I promise to meet a client halfway across the town and I expect to get in that car and go there, and you know,

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I just put it in regularly, get everything checked and I don't want the muffler falling off halfway across town. And the challenge is even greater given all the other things going on. So I would think, you know, pieces of equipment like that. I mean, if you--I assume from this the fact that they were of carbon, they're more apt, yeah, to run out, so therefore--so if you got them somewhere in the middle of your system and people really don't know, you're sort of wondering -
MR. LUDLOW:
A. I think the element of surprise that you're bringing forward, Commissioner Powell, you know, maybe it's the wording, maybe it's not, I don't know. But when this unit went in place in 1983, you know, it was been running pretty consistently through, I think it was '83, '82, '83 range Morris went in place. And from there, upon one of these inspections, subsequent to sticking of the wicket gates they knew there was something wrong. Now, whether they were surprised over the rate of corrosion of the mild steel or whether they were surprised over the fact that it wasn't

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MR. LUDLOW:
stainless and would we have--if we were to do this today what would we buy. Most likely knowing what we know now we'd correct our specification and go forward. I'm not, I'm not overly bothered by the fact that they found a mild steel corroded seal in that it's something that's been running for, you know, 20 years. They found it, they got to it, we were able to manage it in and bring it forward now. So, that's -

Q. Do we have more turbines out there with the same, assuming that it's stainless but it's not? I mean, would you--would that bother you now, you should check all our turbines or -

MR. LUDLOW:

A. Exactly where we would go, we would go now and cross check every--this happens to be a Barber unit that was installed in '83. We would then go and check subsequent purchases and see whether or not they were the same problem. Maybe it's got something to do with the salinity or chemical composition of the water that's causing the mild steel to deteriorate. So, that's exactly the whole idea behind--I

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referenced the asset management of the computer systems. Right now we've inspected, we would log, we know where all other units of this type, date, vintage, manufacturer is. We would go check to ensure that we are not going to have a repeat stuck wicket gate.

MR. DELANEY:

A. Yeah. Well, Barber, just to build on that, the Barber turbine subsequent to this and other things that we have them located in, Lookout Brook plant, at our Lawn plant, Topsail and Morris and (unintelligible) Barbers out of business, are no longer in business, our hydraulic turbines.

Q. The lightening arresters, sort of interesting. Do you have any figures on the percentage of failures of transformers that got hit that had arresters on them as a percentage of the total versus the percentage that got hit that didn't have arresters in the area that you would expect them?

MR. DELANEY:

A. Okay. I can answer this one from a personal experience. In 2002 we had a very severe lightening storm come across Newfoundland. We

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had failures from one end of the island to the other. And in the Grand Falls area was particular hard hit. And we know from our records that in Grand Falls approximately half of the distribution transformers have lightening arresters and half do not.

Q. Um-hm.

MR. DELANEY:

A. Okay. And we had in the order of 200 lightening--transformer failures due to lightening in Grand Falls. And 100--well, all right, all but one were on transformers without lightening arresters. So if you look at that ratio, you think, all right, half your transformers have lightening arresters, half don't. The lightening storm came right through the whole area. You had 200 fail where you didn't have lightening arresters and you had just one fail where you had lightening arresters, so that would give you some idea of the percentages there. And the one that did fail, Earl alluded to afterwards, we were trying to find the transformer. It was a direct hit on the--lightening arresters, I just want to back it up into the operational

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experience on why lightening arresters are such a concern. And as lighting strikes--lightening occurs in summer, of course, in August, and it's a time of year when a lot of people are on vacation. We have a lot of our line staff are on vacation. And if I were to have, say, 500 customers out due to a feeder outage, well, that's one location to go to. I'd send a crew, get the 500 customers back on. If I have 500 customers off due to a lightening storm, I may have as many as 100 different locations to go to, you know, because you have--there's small pockets. Now you got small pockets of problems all over the place, and it's very labour intensive. You send a crew there, you may need four people at the pole, we could be using technology that they used to build the pyramids is what some of the guys say. If they're in the back yards, we have to use block and tackle stuff to get these transformers replaced. So you're combining all of that with a time of year when your resources are, you know, on vacation and it's that time of year when you could be hit with a storm that's causing widespread damage,

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MR. DELANEY:
it's pocketed all over and, you know, it's a concern. I know in the Grand Falls experience we called everybody, got everybody in that was--got them back off vacation, the ones that you can reach. Nowadays with people in cottages and stuff, in cabins, they're sometimes very difficult to reach. And every available person from St. John's to Port aux Basques was mobilized for that particular incident.
Q. Do you have any data within your system outside the province comparable, like you say in Grand Falls essentially you almost had 100 percent success with the--where you had arresters.
MR. DELANEY:
A. Yeah.
Q. Versus--is that -
MR. DELANEY:
A. I don't have no data that I can refer to now, only that I think we're the only ones, really, that don't have lightening arresters. I'm not sure if there's any other utility that doesn't install lightening arresters. It's a matter

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of -
Q. It's all part of it.
MR. DELANEY:
A. Of practice.
Q. One other area we talked about meters. The AMR?
MR. LUDLOW:
A. AMR, yes.
COMMISSIONER POWELL:
Q. Do they have the same life expectancy or is there any benefit in terms of life expectancy or -
MR. LUDLOW:
A. There is no indication, Commissioner Powell, that there would be any difference in the AMR meter, verses the electrical mechanical, if anything the jury is out, they should last longer, from at least the internal workings. And that's not based on, if they haven't been around long enough to find out, but -
Q. No, no.
MR. LUDLOW:
A. Here you're dealing with ones and zeros, or zeros and ones, a digital type technology verses, like I said, springs, dials, meters

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and so on, so that's the sense of the industry.
Q. Have you given any thought to doing a project with, just taking the General Service customers and installing AMRs and all of them because, as a business person, I would think they would want to have the least number of people having access to their place, as possible. So they would, to me, it would be, once explained, would be more amenable to sure, do it if it's going to save me money and convenience and things like that.
MR. LUDLOW:
A. Commissioner Powell, there has been a great deal of thought given to and monitoring all of the meter reading industry in general, and before we actually, I would say jump in, I'd like to wade in very slowly because of the regulatory overtones that I described this morning and the changing, I call it landscape regarding environment, Federal rules, because metering under the Weights & Measures Act is a federally regulated entity. Those are currently behind where we are today in technology, so that's one thing. However,

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that's for a full-blown all out type program. The second piece here that's important is that the business owners would most likely be in the demand style meter--they would be in the demand style meter. And there's a hundred in this budget to test and gain the access and to see how we can in fact talk with the meters, work with the meters and get this--you can almost call this a pilot on its own, I guess, with--while dealing with the accessibility and the safety issues as well. So the long answer, no, we have not gone to a full-blown pilot, but it is not--it wouldn't be a full-blown pilot but a full-blown implementation, but the benefits of moving in that direction, if we can get the other blockages that I just highlighted out of the way, would be a possible consideration.
Q. That's all my questions. Thanks very much gentlemen.
(1:15 p.m.)
MR. LUDLOW:
A. Thank you, sir.
CHAIRMAN:
Q. Commissioner Martin?

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COMMISSIONER MARTIN, Q.C.;
Q. Most of mine are answered, I've just got a couple. There was some discussion about the replacement of a roof in Stephenville because of wind damage and I think you also referred to a vehicle, a few hundred thousand dollars which had been destroyed in an accident. My question is, I was wondering, first of all, if you carry insurance covering those two risks, and if so, if it is factored in the figures we've seen? It's not referred to as a separate item?
MR. DELANEY:
A. In respect to the insurance question, I can answer you on the vehicle. I actually have the numbers here, I jotted them down, having the same question that you've had. That was a vehicle that was involved in an accident in Port aux Basques earlier this year. It was January, February time. It was a very serious accident, by the way, we had a couple of linemen, one lineman in particular was severely injured in that accident. So we had, I think our claim, I'll give you the value of the vehicle at around seventy-five thousand.

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There was a $25,000.00 deductible, so the $50,000 is a result there, in that area. The roof in Stephenville, I'm not sure -
MR. LUDLOW:
A. Generally, I would come back to say that we usually do have insurance for these types of issues, the specifics of the Stephenville case, I don't know at this point. The genesis though, of all of this, is that what we present before this Board is not a net budget, it's a gross budget in that it's not net of insurance proceeds. If that sort of--like the truck, for example, that would be based on the market value at the time of the accident and then the insurance, I think it was $75,000 less the 25 deductible, so there's forty-odd payment back. That in turn goes back against the rate base to reduce the rate base accordingly, but we would not file before this Board for the replacement truck, less the insurance proceeds as a line item in our budget. Is that sort of -
Q. I think so, but the figure that I'm recalling now, and I can't find it here, I thought the figure on the truck was somewhere in the range

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of 300,000?
MR. LUDLOW:
A. It is 300,000, sir.
Q. So that would be a replacement cost, not netted out of insurance proceeds or anything?
MR. LUDLOW:
A. That is the total replacement cost of that vehicle to put a new vehicle on the road. And to give you a flavour of that, first of all, we felt we weren't going to put it back in because we figured we could absorb, but we needed that tandem on the southwest coast. But that is the purchase price, not--there's no netting of any insurance proceeds. That insurance proceeds come back in and go back against rate base and my learned friend, I'm sure, can lead you through that piece a little later on.
Q. And the same thing with the Stephenville one, you're not sure, but the figures in any event would not be netted out.
MR. LUDLOW:
A. Yeah.
Q. In terms of Walbourne's and the situation out in Corner Brook, Bay View and Humber

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substations. There was a load forecast there. I was wondering if factored into those figures would be the loss of the cement plant? The cement plant closed in Corner Brook, I don't know, two or three years ago, something like that, and I was wondering if that is still included as part of the load forecast?
MR. DELANEY:
A. The cement plant, if I can answer that, the cement plant had its own substation transformer and its own supply off of the Bowaters--I keep calling it Bowaters, but Kruger's transmission line -
Q. Corner Brook Pulp & Paper, what it was called.
MR. DELANEY:
A. So, there would be no effect in the Corner Brook transformer capacity, the substation actually was located by Brookfield, McPherson, it'd been taken out of commission just recently. There was a little substation there and that would serve the North Star Cement.
COMMISSIONER MARTIN, Q.C.:
Q. I think all my technical questions have been answered, but there was one reference I saw somewhere to a RF technology. What is RF technology?

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MR. DELANEY:
A. RF technology is the radio frequency technology and it's the way we would read the AMR meters. A meter reader would go along -
Q. Yes, that's right, that's where I saw it to.
MR. DELANEY:
A. - and the information is sent over the airwaves, actually at 900 mega hertz if you want the technical.
COMMISSIONER MARTIN, Q.C.:
Q. Apart from the fact that I can't read my own writing here, I think I've--that probably covers all the questions I've got for this panel. Thank you.
CHAIRMAN:
Q. Thank you. I see we're rapidly approaching 1:30, so I'm going to try and narrow down to probably just a couple of questions. One flows from a question, Mr. Ludlow, that was raised by Mr. Young in his cross and it had to do with the amount of engineering study or engineering detail that took place as part of the budget preparation process for a particular project and what have you. And obviously, you know, I appreciate the fact

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that, you know, it's not going to be feasible or practical to do a full engineering study for a project, as part of the budget process, but I'm wondering, to the extent that, on average, you know, if it's possible to say that a detailed or an engineering study is done in the preparation of the budget process for a particular project. In your opinion, can you indicate what percentage of projects might not subsequently be reflected as over budget if some higher level of engineering of process had been factored in, in the project preparation, you know, for your presentation for the budget.
MR. LUDLOW:
A. I guess ultimately the final stage would be to have your market pricing complete and hopefully there due, unless it were unforeseen, to if, 100 percent on the mark, that's in the budgeting allotments and so on. The approach we've used and I'll come right back to your question shortly, is that when we do penstocks, we would have parameters of cost for 100 meters or, you know, some type of parameter such as that. Similarly with

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distribution in transmission lines, we would base this on proxies that we gathered over decades of work. Like, we know that we've got to build a single phase line for ten miles, we would take that to the stage of the general routing of the line and we know that we can build, a per kilometre base would cost us X dollars, that type. And that's where we are in these budgets here. To take it to the next level would cause a total shift in where we are today in completing 2003 stock, do all your engineering for almost two years in a row, to go forward, that's the secret. I'm not convinced we'd want to move ahead too much further. It could contain a variance somewhat. And I guess that's back to the nub of the question.
I would suggest here, we may be able to trim that variance--I'd be half afraid to put a number on it, to be quite honest. But if I could step up my engineering, it may come ahead, I don't know, 15, 20 percent type range, but even then I don't have it to final engineering stage.
Q. Right.

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MR. LUDLOW:
A. I've never looked at the numbers to be quite honest with you.
Q. I'm just wondering is it worthwhile to try and achieve that 15, 20 percent.
MR. LUDLOW:
A. Well, my goal, to be quite honest with you, as we sit here now is to get the budget before the Board, it gives us half a chance to do some preliminary work from the fall on our long leave time. Like a power transformer, for example, if we were to talk Walbourne's is not a shelf item sitting in Ontario. It's an item, the last one, I do believe, came from Israel and it was something that takes, it takes specifications on resistance and how it ties into the system and then there's whole bunch--that type of detail. Some of that can be done up front, but the market pricing will vary as well. That will impact it.
We're trying to get as much done early in that fall such that we can come out of the blocks early in the year. So, we've caught up a nice bit there, Chairman Finn, but we're not on top of the game yet. My goal is to move

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it.
Q. I was wondering as well, Mr. Ludlow, I think
CHAIRMAN:
in Volume 1, Schedule B, page 61, referencing real property, the renovations and additions to the company, buildings and property, that's not part of the electrical supply to customers. And in 2004 the budget is 174,000 and then the 2005 to 2008, it appears to jump to an annual of $600,000.00 range, if I'm correct. I'm just wondering what the, in general terms what would be creating the substantial increase?
MR. LUDLOW:
A. Sorry, if you could just bear with me one second please.
MR. DELANEY:
A. There was an RFI on this that I was trying to find.
Q. And just while you're looking for that, I guess as an addendum to that particular question, if it's related to new buildings or additions to buildings, if consideration had been given to any sharing facilities with Hydro and what have you, that would take away

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the necessity of any of those additions or extensions.
MR. LUDLOW:
A. Basically, Mr. Chairman, there's several things underneath here, I can give you those examples and then I can go to your second part of that question if you so wish. One of the things we're attempting to do within our own organization right now is to work on consolidation of some properties, areas such as Grand Falls. We currently run a building on Cromer Avenue as well as on the Trans Canada Highway. Depending on where we can go with this, if everything works right and we will be before the Board with the details of that next year, can we, in fact, close one of those buildings, move our cash or whatever and consolidate it down. There are no additions of new buildings within this budget. As in, we wouldn't build another building, we would renovate or change or get--there's enough room there, but we got to make some changes, that type of thing, sorry, no new buildings. I have a two-room building in Holyrood allocated, I'm sorry. But when I think of

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office buildings, I think much larger. This is a district crew establishment in Holyrood, extremely preliminary at this point in time, but to service the bottom of Holyrood, Harbour Main, Conception Harbour, it's about a quarter of the size of this--it's a small shed. It's almost like a baby barn type of situation with a concrete floor and a loading door in the back. We've got--in 2007 we'd be into a HVAC system at Kenmount Road and there's some parking lot repairs that are highlighted there as well. So, that's generally what's underneath this from a -
MR. MYLES:
Q. Excuse me, Mr. Ludlow, Mr. Delaney asked a moment ago about and RFI, I think the RFI is PUB-68 and may assist everyone in going through the numbers.
CHAIRMAN:
Q. That was in relation to AMR meters.
MR. MYLES:
Q. PUB-68.
MR. LUDLOW:
A. PUB-68 is in reference to the general properties included in subsequent years, Mr.

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Chairman.
MR. MYLES:
Q. That was in direct relation to the question posed.
CHAIRMAN:
Q. I'm sorry, I'm looking at the NLH -
MR. MYLES:
Q. I know the feeling.
MR. LUDLOW:
A. The reference in PUB-68 to the Grand Falls service building would be the consolidation.
CHAIRMAN:
Q. Okay, thank you, Mr. Ludlow. A final area, I guess, I just want to get into is in relation to the portable generation and I want to make sure I have a flavour for this. If I refer you to NLH-24 where Hydro requested a table to show the use of Newfoundland Power's previous two portable generators over the past five years indicating for each occasion the reason for its use and the amount of energy generated. If I look at Table 1 and Table 2, does that indicate to me that these portable generators over that five year period were never run for the benefit of Newfoundland

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Power customers?
MR. DELANEY:
A. I can answer that. No, it doesn't. Where you see unscheduled outage for Newfoundland Hydro, that would have been an outage that, let's say, originated on the Newfoundland and Labrador Hydro system, but by running the units we were able to keep the customers of Newfoundland Power, well some of the customers serviced. Okay. The outage, it was an unscheduled outage, so we kept the customers serviced by bringing this unit up. And as well, under scheduled runs for Newfoundland and Labrador Hydro, that's when those units were used to support the system.
MR. LUDLOW:
A. These units are parked now in, most of them are parked actually, one of them is not roadworthy, in Port aux Basques which is at the end of a long radial system, which is the one I referred to earlier. And as such, when we see a scheduled run, that would appear, that who's requesting a run and they would come up to supplement the gas turbine Rose

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Blanche and the other stationary diesel that's down there, to try and support the load from Long Lake up through as far as Doyles, but we're not able to do it. We can only carry about 40 percent or 50 percent on peak.
Q. And if we jump back to the east coast, I guess now, and the portable generator that's included in the '04 budget. It's probably just for some clarification, as well, Mr. Ludlow, it may lead into another question related to this. In your pre-filed evidence, you indicate on page 6 that the 2.5 megawatt portable diesel generator proposed to be acquired at a cost of 1.7 million, will replace capacity that was lost when two existing portable generators and the St. John's diesel generators are decommissioned is 2003. My understanding, I think is that the 2.5 megawatt diesel that was purchased under the 2003 budget, it was indicate then that that particular diesel generator had the benefit of replacing most of the capacity that would be lost with the decommissioning of portable 1 and portable 2, is that correct?
MR. LUDLOW:

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A. It would be much more than two of those, that's correct.
Q. All right. So, that 2.5 more than replaces those two portables.
MR. DELANEY:
A. That's correct.
Q. So, when you say that, in your pre-filed here that the 2.5 portable diesel that you're looking to acquire under the 2004 budget will replace capacity that was lost when the two existing portable generators are decommissioned. That's not entirely accurate, but you do indicate that you do include there that the St. John's diesel generator, you include that there, but the St. John's diesel generator is virtually non-used anyway.
MR. LUDLOW:
A. It's a fixed unit -
Q. Okay. Now, I know that in some discussion that took place in evidence in the 2003 budget, you made mention of the fact, you gave examples of your typical feeder system being a 4 megawatt system and going to use some of these system, you know, these two generators in tandem. But I'm just wondering, if you

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didn't have that 2.5 megawatt portable generator that you're looking to purchase in the 2004 budget and you don't have the tandem process and perhaps you could just elaborate on what you mean by the tandem and how that's going to benefit the east coast. What are you currently doing, you know, when you have an emergency situation and given the fact that you're going to be spending a fair bit of money to refurbish the New Chelsea plant and what have you and that will be in much better shape as part of the '04 budget? You know, how do you handle these emergency situations now and as part of that, assuming that-- obviously you do have a sharing process with Hydro, what portable capacity do they have, you know, that you can benefit from on the east coast and obviously this new portable that you will take delivery of in December '03, you'll be able to transport that from the west coast to the east coast, if you need it. So, if you can just kind of relate these things together for me.
MR. LUDLOW:
A. I'll do my best, Mr. Chair. First of all, in

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the 2003 Capital Budget Hearing which would have been last November, the proposal was

MR. LUDLOW:

filed regarding the site and the sizing of the diesel requirements. And you are correct, Mr. Chairman, when you reference the four to five megawatt range of a typical feeder that's been experiencing these types of outages within our system. And the reason we didn't apply for a single four or five is because of the physical actual weights just will not permit its portability. So, that's the first point. The reference to the loss of generation as a result of the decommissioning of the, it's a 670 kilowatt and a 700 kilowatt, that's the two portables that are sitting in Port aux Basques, keeping in mind that totals to 1.3 megawatts. That's where I was getting to. These were bought at a time in the '70s when feeder levels and loads were much lower and could handle appropriate carrying capacities.

A 700 right now will do nothing for you in any size of a load. So, that's that piece.

From what we do today, if we lose--let's take Trepassey, I'll keep going back there for

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a minute because it's near and dear to my heart over the years. The Trepassey system is one of these long radial transmission systems that I've spoken of here. It's back country. Just to control it can take us eight to ten hours on a good day on bike. If it's foggy, you can't fly it, so--that's the danger zone on the east coast. Old Perlican, that's a separate one I've highlighted. New Chelsea being refurbished, that's status quo. So, I'm leaving that one for the time being. If I have an outage in Trepassey this fall, what am I going to do? Well, I have the options of calling on Hydro's portable generation which, to the best of my knowledge, and I don't have the equipment sharing agreement with me, I'm not sure, I've got two units, I've got one, I do believe up north. I don't know where the other one is, I don't have it in my head, but they're available. I think it's in Roddickton to be exact. We would have 7.2 megawatt gas turbine in Port aux Basques, a mobile. To transport that or the diesel in Port aux Basques to Trepassey would be a minimum of 48 hours down time, assuming we can ge there.

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That's okay. Not okay that it's 48 hours, but its' going to take time. With the parking of the two and a half megawatt diesel on the east coast, what it would provide me with is the capacity to provide some basic essentials down in Riverhead, Trepassey, Portugal Cove South and those areas which is firefighting, water, food, some heat in some community centres. Can I support the full load on that? No, I can't. I can probably take, it's about a 4 megawatt, three and a half, 4 megawatt load, I can carry a piece of it. It will get me going if I had it; if I don't have it, I'm flat broke.

Now, I can transport my other two and a half from Port aux Basques, but I am still in a process to at least limp that system along for 48 hours or three days or whatever. That's the basis.

Now, that's its parking point. Here in the east coast there are locations, Branch, St. Brides, that's a 100 kilometre feeder, Twillingate, I'll go to Old Perlican as a second. That line between New Chelsea and Old Perlican, that transmission line, if that line

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breaks or fails, Chelsea is useless to me, it's on the wrong end of the wire. I got to get something down there. Do I pull it from Port aux Basques? I've got one unit, if I have one unit, I can still only carry a portion of the load. That's the sizing relationship, Mr. Chairman.

So, that's how I'd--today I'd manage, I would be into multiple day outage and I'd be hauling the gas turbine or the two and a half out of Port aux Basques. I don't know if that's any help to you, but it's that type of dynamic in where we located, how we manage, where we put our install capacity and how it's mobile. That is also available under the sharing agreement as well.

Q. Okay. So, in your own wording that you use, you're not looking for a cadillac system, but you want a system that will run. You don't see that as a cadillac system in terms of -

MR. LUDLOW:

A. No, sir. I would not--as I look at this generator, I would be looking at alternatives, I would look at refurbs, I would look at small gas turbines. I mean, it's that type of

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thing, to me--when I look at Trepassey, we talk a lot about alternatives here the last

MR. LUDLOW:

few days, there are several alternatives. One alternative is to attempt to build a line from Fermuse cross country to Trepassey to create a loop system, okay, that's one. Second alternative is to build from Blaketown to Riverhead through St. Catherines into Trepassey, that'll secure the system. A third alternative is to have some sense of mobile generation that will pick up 50 percent better of the load. The other two alternatives are in the seven and a half to eight million dollar range. And what we're trying to do here is provide security in general to a broader base than just Trepassey and hence the mobile unit. So, that's where I'd say a system that'd work.

Q. Right, okay. Leasing this type of equipment is not a possibility, is it?

MR. LUDLOW:

A. Well, I don't think so. I mean, we've looked at some, you know. One, we lease a small unit, but nothing of this type. These are

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custom made utility pieces. If I can a cheaper way to get them, I'd certainly look. I haven't been able to find one yet, that's the way I would answer it.

Q. Thank you. Any questions arising from the Panel.

MR. YOUNG:

Q. I have just one, Mr. Chair. At least, I believe it's just one. I'll see if there's a follow up from the follow up. And this arises from a question asked by Commissioner Powell in an answer Mr. Ludlow gave. The context was the small hydro plant's energy supply issue and Mr. Ludlow, you said something to the point that you had a couple of small hydro plants that you'll have to look at more closely in the future to see if they can be justifiably upgraded, refurbished or whatever. I'm just wondering what sort of analysis that uses and would you use--probably refer you to PUB-124 because that was also in the same context, the same question--a levelized cost approach based on the incremental -

MR. LUDLOW:

A. I'm sorry, I missed your reference.

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Q. PUB-124, sorry I'm running this altogether, I'm trying to economize on time here because I think there's probably one answer to the whole subject matter. I'll just refresh that, just briefly. So, you're talking about--you are aware generally and you didn't give me any specifics and perhaps you don't have them yet, as to some projects in the future that you're going to have to look at closely to see if they're justifiable.

MR. LUDLOW:

A. That's correct.

Q. And I'm just wondering if you can briefly describe the kind of analysis you go through, the kind of figures you look to, and would it be a number of this sort that you'd use when you did that analysis to see if it was justifiable.

MR. LUDLOW:

A. We would certainly use this style of analysis, but whether this is the final determining fact is something that I would have to bring in my accounting team or the financial people of the organization to address. The ones I'm referring to, these are very small plant as

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well that have some factors that--they're very small. It does make New Chelsea look large. The actually financial analysis that we would apply to do a decommissioning of that plant, I'm not in the position to go through the details at this point, Mr. Young, I don't know.

Q. When you put forward the projects that you had put forward, both the New Chelsea one and the one in the general rehabilitation, sort of, the catch all group, project, if I can call it that for a moment. Do you do this kind of analysis for each of those projects to see, in fact, particularly when they're not something which is say, safety or reliability related, but an economic advantage of keeping a good sound economically run, hydro project running into the future. Do you do this kind of analysis in those cases to the projects that you've put forward in this budget?

MR. LUDLOW:

A. We would test the continued future viability of the individual plants on certain types, if they were significant expenditures that had financial implications. I would not run it

though on a 71 year old head gate. I think that's getting to the extreme. I would run it

MR. LUDLOW:

if I had a turbine issues or anything of that type and they were substantive in relation to the plant, yes, I would be monitoring my future flows.

Q. I don't think you've produced any in this application, is that correct?

MR. LUDLOW:

A. That is correct.

Q. That's all, thank you.

CHAIRMAN:

Q. Thank you, Mr. Young.

MR. KENNEDY:

Q. Chair, just one question, it's on dark skies. Mr. Ludlow, did I gather correctly that your chief concern with some of the proposals under the dark skies are safety and security issue related?

MR. LUDLOW:

A. That's two of the items. The third that I have not done any research on is the additional cost from inventory, how this would be managed and the additional training

involved. And there's a whole raft of things that would also creep into the specification of designs. This is--if it was as simple as changing a light bulb in a light fixture, I would go, but I'm not ready to say that.

Q. Okay, thank you.

CHAIRMAN:

Q. Thank you, Mr. Ludlow and Mr. Delaney.

MR. LUDLOW:

A. Thank you, Mr. Chairman, Commissioners.

Q. It's been a long morning, I'm just trying to get some sense now if we are breaking at this time and going to adjourn until 9:00 tomorrow morning. Are we going to finish with the other panel tomorrow?

MR. KENNEDY:

Q. Subject to what my learned friend has, I don't think he has anything for the individuals on the information technology portion. I'm not sure if he has any questions for Mr. Perry.

MR. YOUNG:

Q. I may have, you know, perhaps very little. It depends on what comes up on the presentation, but it's a blank page right now, Mr. Chair.

CHAIRMAN:

Q. I'm taking it appears that in all probability we will be able to finish tomorrow.

MR. KENNEDY:

Q. I think we'll be able to finish both panels tomorrow if we run right through, yes.

CHAIRMAN:

Q. Okay, well then, we'll adjourn at this time until 9:00 tomorrow morning. Thank you.

Adjourned at 1:48 p.m.

CERTIFICATE

I, Judy Moss Lauzon, hereby certify that the foregoing is a true and correct transcript in the matter of Newfoundland Light & Power's 2004 Capital Budget Application, heard before the Board of commissioners of Public Utilities, Prince Charles Building, St. John's, Newfoundland and Labrador on the 11th day of September, A.D., 2003 and was transcribed by me to the best of my ability by means of a sound apparatus.

Dated at St. John's, Newfoundland and Labrador this 11th day of September, A.D., 2003

Judy Moss Lauzon