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(9:00 a.m.)
CHAIR:
Q. Good morning everyone. Any preliminary matters, Ms. Glynn
MS. GLYNN:
Q. None that I am aware of, other than we do have a couple of new faces. Mr. Browne, if you would like to introduce –
BROWNE, KC:
Q. Mr. Bowman is here, Doug Bowman, he's presenting evidence tomorrow or within the next day, all depends. He's been here many times and I think he first appeared here in 1998, so he knows the system.
CHAIR:
Q. I think you have the same tenure with regard to these hearings, Mr. Browne. Good morning, Mr. Bowman. And is there another visitor? No, it's just Mr. Bowman.
MS. DING:
Q. Yes, good morning, Commissioners. I brought with me today our summer student, Andrew Seviour.
CHAIR:
Q. Good morning, welcome.

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MR. SEVIOUR:
Q. Good morning.
CHAIR:
Q. And we'll get going, so it's back to Mr. O'Brien.
MR. O'BRIEN:
Q. Thank you, Mr. Chair. We have Byron Chubbs. Mr. Chubbs would prefer to be sworn, so we'd need the Bible, I guess.
CHAIR:
Q. Good morning, Mr. Chubbs.
MR. CHUBBS:
A. Good morning.
MR. BYRON CHUBBS (SWORN)
CHAIR:
Q. Back to you, Mr. O'Brien.
MR. BYRON CHUBBS, EXAMINATION-IN-CHIEF BY MR. LIAM O'BRIEN
MR. O'BRIEN:
Q. Thank you, Mr. Chair. Mr. Chubbs, would you please introduce yourself?
MR. CHUBBS:
A. Good morning, I'm Bryon Chubbs, vice-president of engineering and energy supply at Newfoundland Power and I've held that

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position since 2018.
MR. O'BRIEN:
Q. And what positions did you hold before that?
MR. CHUBBS:
A. From 2016 to 2018 I was vice-president of customer service with Maritime Electric in PEI, and prior to that, I was director of eastern region at Newfoundland Power.
MR. O'BRIEN:
Q. And do you adopt Section 2 of Customer Operations as your testimony?
MR. CHUBBS:
A. Yes, I do.
MR. O'BRIEN:
Q. Are there any changes you would like to make to the pre-filed evidence and exhibits at this time?
MR. CHUBBS:
A. No, there are not.
MR. O'BRIEN:
Q. Mr. Chubbs, what aspects of Newfoundland Power's operations would you address for the Board?
MR. CHUBBS:
A. I'd like to touch on our operating costs and

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efficiency, our capital program, the reliability of our electricity system and our customer program delivery.
MR. O'BRIEN:
Q. Okay, let's start with the operating costs and efficiency, can you speak to Newfoundland Power's performance in managing its operating costs?
MR. CHUBBS:
A. Newfoundland Power has continually demonstrated sound management of our operating costs. Over the last decade, our operating costs per customer was reduced by approximately 9.5 percent on an inflation adjusted basis. This demonstrates our continued focus on operating efficiency. If we look at it over a longer period and consider the recent cost pressures that are being experienced industrywide, our operating cost per customer from 2013 to 2026 are forecast to reduce by 7.9 percent on an inflation adjusted basis.
MR. O'BRIEN:
Q. Do you have examples of ways Newfoundland Power has been able to improve its operating

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efficiency to date?
MR. CHUBBS:
A. Yes, one example is that we've reduced meter reading costs through automated technology. We've also reduced costs related to customer inquiries through online self service options and a high volume call answering system. Increased automation of our distribution system has also led to operating efficiencies by allowing us to respond to trouble on the system without having to dispatch field crews. We've also leveraged our geographing information systems and our outage management systems to achieve efficiencies in multiple ways, from eliminating duplicate reporting to allowing us to deploy field crews in a more targeted fashion. These are all initiatives that ultimately reduce labour costs for our customers through the use of technology.
MR. O'BRIEN:
Q. Beyond cost savings, how do technologies benefit customers?
MR. CHUBBS:
A. LED street lighting is a good example of a

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technology that provides multiple benefits to customers. LED street lights last longer than traditional street lights, meaning that customers experience fewer street light outages. They provide a better quality lighting that our customers prefer and they provide lower customer rates as soon as they're installed. We've implemented a plan to provide all of our street and area lighting customers with LED fixtures by 2026.

From an operation's perspective, our customers benefit from our new technologies during major storms. For example, during Snowmageddon in 2020, the Avalon area saw 90 centimeters of snow and wind gusts of over 170 kilometers an hour. During that storm, our high volume call answering system automatically answered 18,000 customer calls. Our outage management system automatically assist and grouped 5000 outage reports to predict the location of outages, and the operation of automatic downline reclosures during that storm automatically saved 3.5 million customer minutes of

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outage. This automation allows our crews to focus on restoring service to our customers, instead of spending time searching for faults on the system.
MR. O'BRIEN:
Q. Now we've heard some evidence from Mr. Murray and Ms. London about the effects of inflation, can you describe the impact of inflation that that's had on Newfoundland Power's operating costs?
MR. CHUBBS:
A. Yes, I can. We filed our last General Rate Application in 2021. At that time inflation was forecast to be 5.8 percent from 2020 through to our 2023 test year. Actual increases were significantly higher at approximately 17 percent. Those unanticipated increases in inflation are reflected in our actual operating costs for that period.
MR. O'BRIEN:
Q. Did inflation affect both labour and non-labour costs?
MR. CHUBBS:
A. The impact of inflation was predominantly

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seen in our actual 2023 non-labour operating costs, such as computing equipment and software costs and insurance. The company has limited ability to control these costs as they're subject to external market conditions. These non-labour costs were approximately 12 percent higher than forecast in 2023. That increase is nearly the same as the actual increase in inflation over that period. On the other hand, our actual labour costs were closely in line with our 2021 General Rate Application forecast.
MR. O'BRIEN:
Q. So turning to the 2025, 2026 test years, what's the anticipated impact of Newfoundland Power's operating costs on the rate increases sought in this application?
MR. CHUBBS:
A. Approximately 1.6 percent of the rate increase proposed for July 1st, 2025 relates to changes in operating costs. That includes non-labour and labour costs.
MR. O'BRIEN:
Q. Let's discuss the non-labour costs, what are

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the primary drivers of the change in non-labour operating costs for the test years?

MR. CHUBBS:

A. The three main drivers of changes in non-labour operating costs, computing equipment and software, insurance costs and other company fees. These drivers account for 75 percent of the increase in our non-labour operating cost.

MR. O'BRIEN:

Q. Can you explain why these particular costs have increased?

MR. CHUBBS:

A. Yes, computing equipment and software costs include annual licensing and support fees for hardware and software solutions. Increases in these costs are consistent with general market trends. Cyber security threats have evolved significantly. As a result, maintaining robust cyber security capabilities, up—to-date software versions and security patches is critical. This not only supports our operations, it protects the electricity system and our customers' personal information from cyber threats.

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Insurance costs are increasing at a rate greater than inflation. This is another market trend that is not unique to Newfoundland Power. We retain insurance industry experts who have confirmed that the rates we pay for insurance are the best available.

And finally, increases in the other company fees category are associated with such things as regulatory costs and third party consulting fees.

MR. O'BRIEN:

Q. Now you mentioned labour cost earlier, what impact have these costs had on your application?

MR. CHUBBS:

A. Well coming out of the pandemic many industries sought wage increases, including the utility sector. In fact, most of the utilities in Atlantic Canada have been impacted with comparable collectively bargained wage increases over the period from 2023 to 2026. These increases have a measurable impact on costs. Our internal labour inflation rate will increase by 4.1

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percent annually from 2022 through 2026; however, Newfoundland Power is forecasting actual labour cost increases at a rate of 3.1 percent annually for the same period. This one percent difference demonstrates the company's continued focus on managing its labour costs in an efficient manner.

MR. O'BRIEN:

Q. Now, Mr. Chubbs, you talked about operating expenses, what is Newfoundland Power doing to manage your capital investments?

MR. CHUBBS:

A. We manage our capital investments to ensure we're providing reliable service to customers in an environmentally responsible manner, at the lowest possible cost. We balance the cost and reliability of the electricity system through a comprehensive capital planning process and a focus on the overall cost to our customers. It's important to understand that a large portion of our electricity system was built in the '60s and '70s. These assets are now reaching the end of their service lives of 50 to 60 years. As a result, our capital

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plan has a focus on replacing an increasing number of these assets over the next five years. Over half of our annual capital expenditures are focused on replacing deteriorated and failed equipment.

MR. O'BRIEN:

Q. How does Newfoundland Power ensure that its capital investments are least cost for customers?

MR. CHUBBS:

A. Our capital planning process uses a variety of measures to ensure that our capital investments are reasonable and least cost for customers. These include assessing all viable alternatives for proposed capital projects, deferring capital projects where possible and coordinating related capital projects in a way that ensures they are efficiently conducted. All of our capital investments are comprehensively reviewed by the Board to ensure that they are least cost for customers.

MR. O'BRIEN:

Q. Now you noted the balanced cost and reliability or that you do so, can you

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describe the reliability of service provided to Newfoundland Power's customers?

MR. CHUBBS:

A. Over the last decade our customers have experienced between 2.2 and 3 hours of outage per year under normal operating conditions. That's about 40 percent better than the Canadian average over that period and the frequency of customer outages has been consistent with the Canadian average over the same period. We're focused on preserving current levels of overall service reliability for our customers at the lowest possible cost.

MR. O'BRIEN:

Q. What is Newfoundland Power doing to maintain current levels of service reliability?

MR. CHUBBS:

A. To maintain current levels of reliability, Newfoundland Power must focus on the condition of the electricity system. Our electricity system is constructed to meet national standards. This ensures that our system can withstand the severe weather that is typical throughout our service territory.

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We inspect and maintain our electricity system annually to proactively identify deteriorated equipment.

I mentioned how over half our annual capital expenditures are focused on replacing deteriorated and failed equipment, but we will never completely eliminate equipment failures or weather related outages. It's therefore important that we respond effectively and quickly when there's trouble on our system. On that note, our restoration time for unscheduled outages is nearly twice as good as the Canadian average.

MR. O'BRIEN:

Q. So why is it so important for Newfoundland Power to preserve current levels of system reliability?

MR. CHUBBS:

A. We're seeing a number of risks to the electricity system that underscore the importance of maintaining current levels of reliability for our customers. These risks include a wave of aging assets that are nearing the end of their life, more frequent

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and extreme weather events and the reliability of power supply to the island due to uncertainty with the Labrador Island Link. With all these risks materializing at the same time, we're also seeing more customers converting from oil to electric heat, and driving electric vehicles and working from home. Our customers are relying more than ever on the reliability of our electricity system.

(9:15 a.m)

MR. O'BRIEN:

Q. And now, Mr. Chubbs, you've talked about your operating costs, your capital program and system reliability, let's move on to your customers programs, how do these initiatives reduce cost to your customers?

MR. CHUBBS:

A. We offer a variety of conservation and demand management programs that are aimed at lowing barriers to customer's adoption of energy efficient technologies. Technologies such as insulation and programmable thermostats. These programs include our business efficiency energy savers kit and

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insulation rebate programs. These reduced costs to customers from two perspectives. First, participating customers see savings on their monthly electricity bill and in fact, our customers have experienced bill savings of approximately 180 million dollars from 2009 to 2022 through participation in CDM programs. Second, CDM programs help manage system costs through avoided energy costs and by reducing system peak. We've reduced system costs by another 180 million dollars from 2009 to 2022 through our CDM programs and this benefit is provided to all Newfoundland Power's customers.

MR. O'BRIEN:

Q. Is there anything else you'd like to add on Newfoundland Power's delivery of service to customers?

MR. CHUBBS:

A. Our customer service expectations are always top of mind. We survey 1800 of our customers every quarter and have had consistent customer satisfaction levels over the last decade through these surveys. This indicates that we're meeting our customers'

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expectations.
MR. O'BRIEN:
Q. Does that conclude your testimony?
MR. CHUBBS:
A. Yes, it does.
MR. O'BRIEN:
Q. Thank you, Mr. Chubbs. Open for cross.
CHAIR:
Q. Over to Mr. Browne.
MR. BYRON CHUBBS, CROSS-EXAMINATION BY MR. STEPHEN FITZGERALD
FITZGERALD, KC:
Q. Thank you, Mr. Chairman, I'll be undertaking the cross. Good morning, Mr. Chubbs, Steve Fitzgerald, despite the lack of a name tag, but I think you know who I am. That's okay, don't mean to give you a hard time there. Oh, here it comes. Now we know who I am. Good to know. Just a couple of questions to start, Mr. Chubbs, can you provide us some information regarding your educational background?
MR. CHUBBS:
A. Yes, I can. I graduated from Memorial University, I have a degree in electrical

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engineering in 2006.
FITZGERALD, KC:
Q. And you started work after 2006?
MR. CHUBBS:
A. Yeah, actually I started work at Newfoundland Power as a work-term student in 2004 and I was hired permanently in 2006 as a distribution engineer in the Corner Brook office.
FITZGERALD, KC:
Q. Okay, so currently you're the VP of energy supply and planning, correct, as you've just identified.
MR. CHUBBS:
A. VP of engineering and energy supply.
FITZGERALD, KC:
Q. Energy supply, sorry. And you're part of the executive compensation plan.
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:
Q. And can you tell us what the maximum payment is for your benefits?
MR. CHUBBS:
A. Or benefits, are you talking –

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FITZGERALD, KC:
Q. Sorry, you've been given—we were discussing yesterday or the Consumer Advocate was asking questions yesterday about the incentive targets that the executive team has, so that was my question, really. So what's your maximum payment under those STIs?
MR. CHUBBS:
A. So in terms of STIs, so my STI would be, would amount to 35 percent of my annual compensation and then there's a range to that that you can receive between zero percent and up to 200 percent depending on performance and how you meet your targets throughout the year.
FITZGERALD, KC:
Q. And you've been a VP since 2016, I think, is that—or 2018?
MR. CHUBBS:
A. I've been a VP at Newfoundland Power since 2018 and I was also a VP at Maritime Electric in 2016.
FITZGERALD, KC:
Q. Right, did they have a similar STI program

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there?
MR. CHUBBS:
A. Yes, it was similar yes.
FITZGERALD, KC:
Q. And did you achieve your targets while you were with Maritime Electric?
MR. CHUBBS:
A. No, their STI program has multiple targets that we measure, from customer service to reliability to managing operating costs. Some years you do better in some areas than others, you know, some years, for example, you know, a poor year on reliability and you don't meet that target, other years operating costs, in which the operating cost pressures like we've seen at Newfoundland Power over the last few years, so I haven't met all targets all years, no.
FITZGERALD, KC:
Q. Okay, but you've always received or have you, some portion or some amount for STI, just not the full amount, is that—has there ever been a year that you didn't receive any portion of a STI with Newfoundland Power?
MR. CHUBBS:

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A. No, there has not.
FITZGERALD, KC:
Q. What about with Maritime Electric?
MR. CHUBBS:
A. No, there has not.
FITZGERALD, KC:
Q. So how many fulltime employees at Newfoundland Power would report to you?
MR. CHUBBS:
A. Probably around 200, I would think.
FITZGERALD, KC:
Q. That's a lot.
MR. CHUBBS:
A. Not directly to me, now.
FITZGERALD, KC:
Q. Sure, and according to the org. chart, we don't have to go there, but Mr. Comerford who is going to be testifying as well, he's the director of rates and supply and he reports to your directly, is that correct?
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:
Q. And can you confirm that you are responsible for the asset management, distribution and

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planning in rates with Newfoundland Power?
MR. CHUBBS:
A. Say it again, so responsible for asset management, distribution planning –
FITZGERALD, KC:
Q. Distribution planning and rates.
MR. CHUBBS:
A. And rates. Yes, Mr. Comerford reports to me, he's responsible for rates and the rate design study we have ongoing.
FITZGERALD, KC:
Q. Right.
MR. CHUBBS:
A. Asset management reports through me through our director of engineering and distribution planning, similarly.
FITZGERALD, KC:
Q. They all report to you.
MR. CHUBBS:
A. Yes.
FITZGERALD, KC:
Q. Yes, okay. And just turning to the preparation for this GRA, which components of this were your direct responsibility?
MR. CHUBBS:

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A. So my direct responsibility would be largely related to Section 2, our operating cost, capital program, capital cost, reliability and electricity system, and our customer service delivery.
FITZGERALD, KC:
Q. Okay. Mr. O'Brien took you through those topics this morning. Did you receive any direction from the president and CEO and the CFO regarding the preparation for this GRA?
MR. CHUBBS:
A. I mean, preparation for the General Rate Application is a constant conversation that Newfoundland Power as certainly as we're leading up to our application, so we would have worked together on the General Rate Application certainly.
FITZGERALD, KC:
Q. Sure, were there any particular areas that were trouble spots, if you were or if you would that required extra attention or extra direction or areas that the company thought should be emphasized in this GRA?
MR. CHUBBS:
A. I think in my direct I probably covered the

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key topics, you know, to emphasize, right, in terms of operating costs, our labour efficiencies, some of the non-labour inflationary increases that we have seen over the last few years and going forward, the reliability of the electricity system and our performance would be another, our capital program and our focus on managing our capital costs would be another and certainly our customer program delivery in terms of reliability, in terms of customer service that we provide to our customers, so those would be areas of focus for me.
FITZGERALD, KC:
Q. I noticed this morning you mentioned, and Ms. London mentioned as well when she was on the stand, about the troublesome thing, I call it troublesome, but the issue of insurance seemed to be spiking or an area that was creating a concern for the company, and you mentioned that this morning in your testimony, correct?
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:

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Q. And I'm just going by memory now, Ms. London had indicated that that was an increase beyond Newfoundland Power's control and I believe that you indicated that's the case this morning as well.
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:
Q. But you also said, I think, that when it comes to the insurance and we don't have to go to the line item there, I believe the increase was, I think you said 12 percent over, from 2023 to 2025?
MR. CHUBBS:
A. That's the general inflationary increase that we saw, so when we looked back in 2021 when we were preparing our rate application at that time, the forecast inflation that we had over the next few years, up to 2023, based on, you know, information that we had at the time, we expected to be around 5.8 percent. What we actually saw over that period was around 18 percent, so that was 12 percent higher on overall inflationary costs.

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FITZGERALD, KC:
Q. Right, and insurance was a component of that.
MR. CHUBBS:
A. Yes, insurance was a component of that.
FITZGERALD, KC:
Q. So mentioning it here this morning, you know, when the GRA was being formulated, was thought put to that, saying, look, this is, it seems to me a lot of emphasis being put on the insurance increase, but if you go to Exhibit 3, I guess we can go there now and look at it, I think Exhibit 3 is Undertaking U-01, Attachment A. That may not be correct, bear with me for a moment. Yeah, no, that's not the correct one, there's a breakout of the insurance cost year over year from 2022 and I'm not sure exactly which exhibit that is on now.
GREENE, KC:
Q. It's PUB Information Request No. 2.
FITZGERALD, KC:
Q. Okay.
GREENE, KC:
Q. Schedule 5, Attachment 5, you will see it there, is one place.
FITZGERALD, KC:
Q. All right, thank you Ms. Greene. I don't think that's the right one.
GREENE, KC:
Q. No. It's PUB Information Request No. 2, the additional information. That's one place you'll see it in a nice orderly way from 2022 to '26. Schedule B, Attachment 5.
FITZGERALD, KC:
Q. Okay, thank you. The line 15 there, you know, you got the annual cost as 2.3 million in 2022 and then it escalates, the forecast to 2.9. You know, when you look at all of the numbers, although I'm not saying it's not significant, it doesn't jump out at me as--it's obviously escalating, but it doesn't seem to be the main problem with, you know, I know it's a cumulative affect, but why isn't insurance being sort of isolated or red flagged, if you will, as—is it just used as an example of increased operating expenses?
MR. CHUBBS:
A. Yeah, like over the last few years our

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insurance costs have increased in double digit figures, so about 10 percent is what we saw from 2021 up to 2023. We've seen this, you know, annually year over year. These costs, you know, they're driven by what's going on in the market right now and they've been certainly a pressure for us in our last rate application and, you know, we see it as a potential future pressure for us as well.
FITZGERALD, KC:
Q. And I got the impression from Ms. London when she testified that the—and I think you repeated it this morning, that you believe or Newfoundland Power believes that they are getting the best available cost or price available or best coverage, or best price, I think, with their current provider. Did I hear you correct on that?
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:
Q. But she also said that really and the provider is AON Reed Stenhouse she testified, that is Fortis, the parent

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companies insurer and I believe she indicated that Newfoundland Power believes they are getting some economies by being a member, if you will, of the Fortis family and getting some breaks, so you agree with that, that's generally what she said?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. And that's what you understand as well.

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. But she also said, of course, that there's been no initiative by Newfoundland Power to go outside the AON Reed Stenhouse coverage, no one at Newfoundland Power is tasked as an operating expense, expenditure, cost saving initiative to check other providers of insurance and I believe she might have deferred that, because I asked her about that and she might have deferred that to you and would you confirm that that's the case, no one is looking to see if there's a better price out there at Newfoundland Power?

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(9:30 a.m.)

MR. CHUBBS:

A. So AON, our insurance broker that work on behalf of Fortis, so they're taking Fortis insurance program to market. There are multiple insurers, as I understand it, that participate in that insurance program that provide insurance through the program, you know, so they're working on behalf, they're a third party working on behalf of Fortis as a broker, right.

We did file, as part of, following Ms. London's testimony, an undertaking that showed the last time we reviewed this, which would have been I think part of our last rate application, where we did a side-by-side comparison to show the insurance that we had, the coverage that we have under our existing program through the Fortis plan and AON used that coverage, compared it to what it would look like if Newfoundland Power were to go out on its own to seek the same coverage or coverage appropriate for Newfoundland Power, and I believe it showed that the cost would double if we were to go

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out on our own and seek our own insurance by ourselves, right.

So the Fortis program gives us access to that broader market and we get a lower rate due to the geographic diversity, the lower risk that you get, you know, from a larger insurance program. So it definitely provides benefit to Newfoundland Power and to our customers.

FITZGERALD, KC:

Q. Right, which is the point, I guess, from our perspective, but this information, again, derives, the comparative analysis derives from your current provider, correct?

MR. CHUBBS:

A. The current broker, yes.

FITZGERALD, KC:

Q. The current broker, well there are other brokers in this geographic region, of course, you would agree?

MR. CHUBBS:

A. Yes, I would agree.

FITZGERALD, KC:

Q. So none of the other brokers have actually tested this information, correct?

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MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. So would you know if Fortis itself, the parent, gets any benefit of adding Newfoundland Power to its, you know, coverage—sorry, that wasn't worded correctly. Fortis is bringing Newfoundland Power to AON as a customer with, you know, 2.3 million dollars per year in 2022. Do you think Fortis gets any advantage by bringing Newfoundland Power to AON Reed Stenhouse?

MR. CHUBBS:

A. I think all Fortis subsidiaries get an advantage of participating in the Fortis plan. I think you get that broader geographical diversity that allows that risk to be spread over multiple utilities, and as a result, the utilities participating in that plan get an overall rate and that lower overall rate gets passed on to the customers of those utilities, including Newfoundland Power's customers. I'm not aware of any other benefit that would be provided to

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Fortis through Newfoundland Power participating in the plan and I think it's worth pointing out that Newfoundland Power's 3 percent of Fortis, in terms of total assets, so I'm not sure that that 3 percent incremental increase of Newfoundland Power participating or not participating provides a broader benefit to Fortis. I can't see how that necessarily would work.

FITZGERALD, KC:

Q. Sure, but neither one of us know, really. I've asked the question, but you wouldn't really know if there's any benefit or not?

MR. CHUBBS:

A. No, I'm not aware of any benefit.

FITZGERALD, KC:

Q. Just turning to another topic, Mr. Chubbs, if we could go to the transcript, June 14th, 2024, page 53, and it's line 9. And Board counsel, Ms. Greene, is cross-examining Mr. Murray and she does a tally here of the increases that are pending in power costs and said "If we add all these up, we would get over 20 percent increase and if we add on the 2.25 to come from Hydro next year on

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July 1, arising from rate mitigation we're almost up to 23 percent." And Mr. Murray says, "That's correct". And then Ms. Greene goes on and asks a question, "Do you recall a rate increase being proposed by Newfoundland Power of that magnitude in such a short period of time?" And Mr. Murray says, "No." And then if you keep going further down, sorry, scroll a little further, page 55, line 4, "And are you aware that in the past the Board has considered a 10 percent increase for customers as rate shock", again, this is a question from Ms. Greene, and Mr. Murray says, "Yes, I'm familiar with that." So you would agree with Mr. Murray that an increase of that amount does amount to a pending rate shock?

MR. CHUBBS:

A. You know, I've seen the term "rate shock" used in a number of proceedings and, you know, the 10 percent number has been used and I think used by the Board at times too, have aligned with the term rate shock and yes, the increases over the next two years are in that range, yes.

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FITZGERALD, KC:

Q. So from your perspective or what would your definition of rate shock be? What are the effects?

MR. CHUBBS:

A. I'm not sure I could be any effects to rate shock, you know, it's a general term that's been used. I am not aware of anything that happens at 10 percent versus 9.5 or 10.5 or, you know, what would necessarily, what happens once you hit 10 percent. I think it's just a general level of rate increase that, you know, when you're getting into the territory of it's a big, one-time increase for customers.

FITZGERALD, KC:

Q. But what is the impact on customers if they're encountering rate shock?

MR. CHUBBS:

A. Well in terms of, I think you're getting into elasticity, is that –

FITZGERALD, KC:

Q. Yeah, I mean I guess the point is you see, your department sees what Mr. Murray has identified as rate shock coming. Obviously

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that has to do with elasticity in sales, so at what point does your department says "we better get ready for this"?

MR. CHUBBS:

A. You know, we're continually looking at our forecast, our customer forecast, we incorporate the impacts of rate increases over time into those forecasts, just like other increases and decreases in terms of, you know, general sales, customer growth, electrification, all those matters, so we continually build those into our customer forecasting. So we do that on a regular basis, so in terms of getting ready, I'm not quite sure where you're going there.

FITZGERALD, KC:

Q. Well you see, I guess the rate shock that's been identified, I mean if 10 percent, an increase in rates, is generally regarded as going to create a rate shock and therefore elasticity in prices, but we're actually at a level of 20 percent, I would have thought that alarm bells might be doing off at Newfoundland Power as to, you know, price elasticity and are there any preparations

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being made for what, you know, as a layperson I could expect is going to occur with a rate shock of this magnitude?

MR. CHUBBS:

A. I mean, Newfoundland Power is certainly aware of the rate increases and pressures that are occurring right now. When you look at that 20 percent or so, a large portion of that is related to our supply cost, right, and this issue with the wholesale rate and such. In terms of Newfoundland Power, you know, we are continually focused on managing our costs through efficient operations, reducing our costs, labour costs where we can and we continually do that over time.

We have a lot of programs out there to support our customers in terms of, you know, who may be concerned about rate pressures, whether that's flexible payment arrangements for customers or providing customers with energy efficiency tips or we have programs that are available for our customers in terms of support and rebates for things like insulation and programmable thermostats and programs like that to support customers who

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may be having a challenging time with their electricity bills.

FITZGERALD, KC:

Q. Sure. Would you think that this Board, the Public Utilities Board would have any role in this anticipated rate shock? For example, would you be surprised in the Board had a hard look at controllable expenses within Newfoundland Power to mitigate the pending rate shock?

MR. CHUBBS:

A. The costs that we have put forward in our application are the reasonable costs that we feel are necessary to operate the electricity system. These are all costs that are based on our experience, our operating experience historically, we've incorporated the effects of inflation in our costs, any known and manageable changes in our costs.

And in our view, the costs that Newfoundland Power have included in our rate application are costs that are required to provide reliable service to our customers in an environmentally responsible manner at the

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lowest possible cost. So we feel that what we have put, included in our application, is appropriate and is reasonable.

FITZGERALD, KC:

Q. Again, that of course is your position, but I guess the, my question is would you be surprised if what you regarded as reasonable, your controllable costs I'm talking about now, any portion of them would be disallowed by the Board in the environment that we're in?

MR. CHUBBS:

A. I that, you know, in this hypothetical scenario, I think I'd have to understand what costs were disallowed and why before I could gauge my reaction. I do feel though the costs are reasonable and appropriate.

FITZGERALD, KC:

Q. So the cost of service model that is included in the GRA, what inputs to that cost of service model were provided by your division?

MR. CHUBBS:

A. You know, Mr. Comerford would be best to speak to cost of service and cost of service

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model, he's covering, you know, cost of service as part of his evidence.

(9:45 a.m.)

FITZGERALD, KC:

Q. Okay. Can we have a look at Newfoundland Power's Rebuttal Evidence, this is the document that was filed on the 28th of May, 2024, so Mr. Chubbs, this is testimony, it's evidence, do you adopt this evidence as yours or Newfoundland Power's?

MR. CHUBBS:

A. This is Newfoundland Power's Rebuttal Evidence, yes.

MR. O'BRIEN:

Q. Mr. Chair, I've had a discussion with counsel this morning, Mr. Comerford intends to adopt this evidence as part of his testimony, but I have no objection to any questions that Mr. Chubbs may be able to answer at this point, so subject to that proviso.

CHAIR:

Q. Okay.

FITZGERALD, KC:

Q. Thank you. But you have—you are familiar

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with this evidence, though, Mr. Chubbs, are you?
MR. CHUBBS:
A. Yes, I am.
FITZGERALD, KC:
Q. Okay, can we go to page 18? This comment kind of jumped out at line 9, it says—well it starts at line 8, it says, "The Bowman evidence did not provide comprehensive studies, jurisdictional comparisons or customer benefit and cost analysis to support its recommendations. Overall the recommendations appear to be primarily based on Mr. Bowman's opinion of certain information on the record of this proceeding, as well as his prior work experience and engagements." And was that last sentence, was that a criticism of Mr. Bowman's methodology?
MR. CHUBBS:
A. I don't think I can really speak to that statement. I think that's better for Mr. Comerford to cover. He would have been closer to Mr. Bowman's evidence and the review of his evidence.

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FITZGERALD, KC:
Q. Sure, okay, fair enough. I mean, as I read it, you know, the recommendation is primarily based on Mr. Bowman's opinion of certain information on the record of this proceeding, as well as prior work, I don't know what else it would be based on, would you? I mean, he was required to examine and analyze the record of the proceeding, that's what his evidence was based on.
MR. CHUBBS:
A. Yes, and you know, the statement is, you know, prior to that, talks about any other studies or jurisdictional scans that may have been provided as part of the evidence. So, it's difficult sometimes to assess where, you know, an expert such as Mr. Bowman might be coming from in some of these recommendations. So, you know, I think that would be the basis of it. But again, I think Mr. Comerford would have been closer to reviewing the evidence and his submission. So, I'll leave it to him to get into detail on it.
FITZGERALD, KC:

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Q. Okay. Well then, let's look then at page 20 of the rebuttal evidence, and line 6 says, "Newfoundland Power proposes changes to its customer rate structures based on comprehensive reviews". Now, is this going – a topic that Mr. Comerford is going to be talking about or can I ask you questions on this or should I ask you questions on this?
MR. CHUBBS:
A. Again, Mr. Comerford is closest to this in terms of rate design and the rate design review, and he certainly can speak to this at length, but feel free to ask a question and -
FITZGERALD, KC:
Q. Okay. We'll give it a go.
MR. CHUBBS:
A. Okay.
FITZGERALD, KC:
Q. So, can you confirm that Newfoundland Power proposes to increase each component of each of its retail rates by the proposed rate increase of 5.5 percent?
MR. CHUBBS:
A. I think generally they're all around the

Page 44

same amount. Off the top of my head, I feel like there's one that's different, but I can't specifically recall.
FITZGERALD, KC:
Q. Which of the ones you're talking about, which component are you thinking might be different?
MR. CHUBBS:
A. Actually that's not – it's not coming to my mind right now, sorry, but they're all generally moving around the same amount, yes.
FITZGERALD, KC:
Q. Okay. All right. Were any alternative retail rate options considered to recover the proposed increase in revenues?
MR. CHUBBS:
A. We were completing this rate design review. Right now we're in the midst of that review and any alternative rate designs, I think would be appropriate to wait until that review is completed. You know, at the same time, right now, I mean, we're in the midst of a big change in the electricity sector. We're seeing embedded cost change as a

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result of Muskrat Falls. We're seeing changes in our wholesale rate occurring right now, and again, we're in the midst of a review. So, this rate application, in our view, was not the appropriate time to be changing rate design and we certainly want to see the outcome of this review, the results of that before we start implementing those designs and ensuring that we're considering the impact on all customers when you change rates. It's not something you want to do without, you know, a comprehensive review.

FITZGERALD, KC:

Q. Right. So, and I guess you'd have the same answer if I – you know, if I asked you, you know, had you guys – or Newfoundland Power, sorry, considered, you know, a deferral account for these rate changes. I guess you would – that would be another method of collecting the revenue financially.

MR. CHUBBS:

A. What kind of deferral account? Specifically what cost would be in that deferral account?

FITZGERALD, KC:

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Q. Well, you know, no change in rates, did you consider not changing the rates at all but recovering any approved revenue increase via a deferral account?

MR. CHUBBS:

A. So, you're meaning recovering those costs from customers in the future?

FITZGERALD, KC:

Q. Yeah.

MR. CHUBBS:

A. Is that what you're getting at? I mean, we operate under a cost-of-service model. We're a cost-of-service jurisdiction. You know, under our regulatory processes, you know, we collect those costs from customers under that model and, you know, deferring a cost like that, you know, you're getting into the intergenerational equity, right, and whether that's appropriate or not. So, it's not something that we've considered here.

FITZGERALD, KC:

Q. Okay. So, but obviously, you know, you've put forward this 5.5 percent increase and there was some thought process here because

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it says that. In the rebuttal evidence it says, "Newfoundland Power proposes changes to its customer rate structures based on comprehensive reviews". So, we take that to mean that prior to putting forward the 5.5 percent ask that there was a comprehensive review undertaken, and is that the case?

MR. CHUBBS:

A. We're talking comprehensive review here. We're talking about changing rate structure. So, we're talking about, you know, adding additional blocks to rates. You're talking time of use rates, critical peak pricing, you know, increasing blocks, declining blocks, all those types of things. So, in terms of rate structure, our rate structures are the same. There's no comprehensive review completed because these are the rate structures we operate under. What we're talking about here is whether we may want to change those rate structures, you know, because of the change we've seen in the electricity sector, because of the changes in the wholesale rates and the marginal cost that we're seeing, and this is why we're

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completing this comprehensive review right now. That takes time and you need to be thoughtful of things. Like for example, you know, if you were to put in a second block, a lower second block for customers, that would impact customers differently depending on the usage of that customer. So, a customer with say a very large home and consumed a lot of electricity, they might see their bill go down because they're getting a – taking advantage of that second block of energy, if they have high consumption, where a customer in a smaller home who doesn't use as much energy in that home may be focused more on conservation, they would see that first higher block, you know. So, you need to really be considerate to the impacts on your customers when you're implementing new rates and rate structures.

FITZGERALD, KC:

Q. Okay. So, well, you've put forward a request to increase each component of each retail rate by 5.5 percent. So, you know, and I take it that – I don't want to put words in your mouth, but there was no

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comprehensive review undertaken prior to that being put forward, but there is an affect on each of the components by asking for a 5.5 percent increase across the board.

MR. CHUBBS:

A. Yes, I mean that would be consistent with all of our rate applications historically, and again, you know, our rate structures are as they are. Changing rate structures is a whole different thing. That's where you need to really consider the impacts on your customers and you would want to complete that review.

FITZGERALD, KC:

Q. Okay. So, just – and maybe this is Mr. Comerford's area. I understand that Newfoundland Power's tail-block energy charges are already well above marginal energy costs. Is that true?

MR. CHUBBS:

A. Yes, and I think Mr. Comerford certainly would be the best to speak to that.

FITZGERALD, KC:

Q. So, but that component, tail-block energy charge, that's going to be increased by 5.5

Page 50

percent. So, that's going to take them even further away from marginal energy costs?

MR. CHUBBS:

A. I think it's best for Mr. Comerford to speak to the specifics of that.

FITZGERALD, KC:

Q. So, generally, does Newfoundland Power believe that the wholesale rate, which is being worked on, should reflect marginal cost to improve the efficiency of the pricing? That's the principle behind that I understand.

MR. CHUBBS:

A. Yes, that's the general idea. The wholesale rate that we receive today from Newfoundland and Labrador Hydro is based on the historical wholesale rate which is driven by fuel cost at Holyrood being the marginal cost. Whereas today, the fact that we're interconnected to the national grid, marginal cost really reflect energy costs on the open market. So, they're lower compared to Holyrood.

FITZGERALD, KC:

Q. So, shouldn't the retail rates reflect

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marginal cost to improve the efficiency of the price signal?

MR. CHUBBS:

A. I think that's something that we need to complete this review to fully understand.

FITZGERALD, KC:

Q. Page 20 again of your rebuttal evidence, and again, we're talking about the – line 10, talking about this comprehensive review and then at line 12, it says, "for example, establishing a declining block rate structure for domestic customers, as recommended by Mr. Bowman, may encourage customers to consume more energy during winter peak periods when capacity on the Island Interconnected system is limited." So, currently though, there are rates for general service customers that have a declining block rate structure? Isn't that correct?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. And Newfoundland Power's proposing a continuation of that or for general service

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customers?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. So, what's the difference if it's okay for general service customers?

MR. CHUBBS:

A. So, the declining block structure now for general service actually reflects the energy costs on the electricity system more closely now than what our current wholesale rate cost does, and I believe in the report from Christensen, the phase one report of this review, identified that the current rate structure we have today are actually fairly suitable. It sets us up for the wholesale rate marginal costs that are coming; that are actually being experienced on the system right now. So that declining block rate might make sense.

FITZGERALD, KC:

Q. Might make sense for the general service?

MR. CHUBBS:

A. Yeah. And again, we'll see what comes out of this review and whether, you know, that

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continues to be appropriate for general service customers or not. But it's something we need to fully review and fully understand.

FITZGERALD, KC:

Q. Just turning to the load research study that was negotiated the last GRA and it's referred to in the rebuttal evidence at page 21 and referring to response to a PUB RFI there. It stated here that "the response explained" – that is Newfoundland Power's response – "explained that the necessary meters were delayed due simply to the supply chain constraints which have impacted the utility industry in recent years". And the Load Research Study was part of the settlement agreement back in 2023 – or 2022, correct?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. And I guess you're saying – you go on to say at page 21 – I lost my – yeah, no, at page 11. "Bowman evidence recommends that Newfoundland Power give highest priority to

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the Load Research Study." We're three years on and nothing's really occurred, but you indicate that that's because of the supply chain issue. Is that the only reason why the Load Research Study wasn't – isn't progressing?

MR. CHUBBS:

A. Well, that's a large part of it. I mean, you need the meters to be able to conduct load research to get that granular data that our current meters cannot currently collect. So, we can't really complete a Load Research Study without the appropriate meters to gather the data that we need. So, that takes time and like many things, meters are experiencing supply chain delays and issues and these have impacted this study. Mr. Comerford can speak to anything outside of that that may have impacted the schedule, but as I understand it, the large part of it has been the delivery of the meters to complete the load research.

(10:00 a.m.)

FITZGERALD, KC:

Q. During this period, while you were suffering

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from this supply chain deficit, was Newfoundland Power able to procure other meters for its use or was the supply chain issue specific to the meters that you were looking for for the load research?

MR. CHUBBS:

A. We haven't had any issues with meters, our regular AMR meter deliveries. Those would be largely routine deliveries for Newfoundland Power. These load research meters, you know, you're talking about a small number of meters specific for Newfoundland Power that when we speak to our meter supplier, they have – because of their other meter orders that they have, they haven't been able to get those in the assembly line essentially to get them delivered to Newfoundland Power. So, they have a backlog of orders, including Newfoundland Power, but other customers that they're delivering meters and we weren't able to – you know, or it's taken time to get these meters produced for Newfoundland Power.

FITZGERALD, KC:

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Q. And that's a different type of meter you're talking about now? Is that -

MR. CHUBBS:

A. That's right, yeah. So, you know, the meters we have today are what we call AMR meters, automatic meter reading. They essentially produce a read – they gather your monthly reading, produce that one monthly reading for billing purposes, whereas these load research meters would be collecting interval data, you know, on 15-minute interval data, so they could collect, gather a lot more information and that information needs to be collected from the meter itself. So, it's a different type of meter, a bit more specialized.

FITZGERALD, KC:

Q. And they're harder to get than the AMR?

MR. CHUBBS:

A. I don't know if it's fair to say that they're harder to get. I mean, you know, these types of meters and AMR meters, you know, are routine meters, but this was a special order of a small batch of meters for Newfoundland Power for this specific purpose

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and our meter manufacturer/supplier aren't able to meet that order in I'll say our traditional delivery time timeframe. So, as a result, this has delayed the Load Research Study.

FITZGERALD, KC:

Q. Okay. So, the statement there where it says, "Mr. Bowman's recommendation to give highest priority to the Load Research Study is redundant in consideration of the company's ongoing efforts". I would take the inference from that is that Newfoundland Power is giving the Load Research Study the highest priority. Would you agree with that?

MR. CHUBBS:

A. Yes, it is a high priority for us to deliver this Load Research Study. It's something we want to complete. Right now we're into the practical effects of meter delivery delaying the study and it's not much that Newfoundland Power can do right now to advance it anymore quickly than is currently occurring.

FITZGERALD, KC:

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Q. So, is there a particular source where you're getting the meters that you need from or not getting from – not getting them yet, but you have a contract out for these?

MR. CHUBBS:

A. Yeah, so Newfoundland Power's meter supplier is Itron. They are, as I understand, the largest meter manufacturer in North America, and if not the largest, certainly one of the top meter manufacturers. And I believe the meters that we've ordered are Itron meters. I, you know, stand to be corrected that they're not coming from another manufacturer. I'm fairly certain they're Itron meters.

FITZGERALD, KC:

Q. And they're based out of where?

MR. CHUBBS:

A. I'm not sure. I don't know where Itron is based out of.

FITZGERALD, KC:

Q. But there's a contract let at some point between Newfoundland Power and Itron meters for these load research meters?

MR. CHUBBS:

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A. Yes, and Mr. Comerford can give you more details on that, but yes, the meters are ordered. We're just waiting on delivery.

FITZGERALD, KC:

Q. Okay. Would you know when they were ordered?

MR. CHUBBS:

A. No, I do not.

FITZGERALD, KC:

Q. Would you be able to approximate since 2020? Would it have been 2022? If you don't know, you don't know, but I mean, if you could approximate? If it came past your desk and you can recall, perhaps you could tell us.

MR. CHUBBS:

A. No, I can't recall. Mr. Comerford will be able to speak to it certainly.

FITZGERALD, KC:

Q. Just turning to another topic, Mr. Chubbs, and I don't know if we have to go to P.U.5 (2019), but we might as well be ready, and I'll ask you general questions and if you can't recall, then we'll go to it, but this was the Board order dated February 19th, 2019 and it was approval for 4.6 million for the

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Long Pond Substation. Do you recall that order?

MR. CHUBBS:

A. I recall getting the order.

FITZGERALD, KC:

Q. Okay. So, you're not going to dispute that that in fact occurred; that the Board did approve a 4.6-million-dollar amount for the Long Pond Substation. We know that as a fact.

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. Right. And would you also know as a fact that that amount, 4.6 was fully contributed by the customer, being MUN, because the substation was deemed to be a special facility?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. Okay. Do you know when that substation was declared in service?

MR. CHUBBS:

A. I can't recall the specific date. It would

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have been in – would have been within, you know, a year and a half or so of the order.
FITZGERALD, KC:
Q. So, 2020 or 2021?
MR. CHUBBS:
A. Yes.
FITZGERALD, KC:
Q. And you would recall as well that on February – in February 2023, Newfoundland Power filed an application for an upgrade to that substation for 3.3 million dollars?
MR. CHUBBS:
A. An expansion to the substation, yes.
FITZGERALD, KC:
Q. Was it an expansion or was it a replacement of a transformer?
MR. CHUBBS:
A. We're talking Long Pond substation?
FITZGERALD, KC:
Q. Yes.
MR. CHUBBS:
A. It was an expansion of the substation. So, Long Pond substation was requested by Memorial University to provide a redundant feed on the backside say of the university,

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and then the subsequent project was related to the new boilers that MUN are installing, the electric boilers that MUN are installing at their facilities and so that increased capacity required a second power transformer and extension to the substation to serve that load. So, the current – the transformer that was installed say in 2021 is still there as a redundant transformer that was funded by the university.
FITZGERALD, KC:
Q. So, it's redundant, and I don't know the term of art, does that mean it's stranded or of no use or is it – it's still in use, the old transformer?
MR. CHUBBS:
A. Yes.
FITZGERALD, KC:
Q. Or the relatively old transformer. It's relatively new, but the first transformer.
MR. CHUBBS:
A. Right. So, it's not stranded. Redundant meaning a backup supply for the university. So, they can use it for their own purposes in terms of, you know, the university's

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system is interconnected. They can move load from one – from buildings from the current MUN substation to the Long Pond substation for their own purposes, for work that they need to do or for any reason, you know, we couldn't serve the load from MUN substation, we could serve it through Long Pond substation. So, it serves a second supply, redundant backup supply for the university.
FITZGERALD, KC:
Q. Okay, thank you. And we understand that that 3.3 million dollars was not paid by the customer. That's paid by the ratepayers, correct?
MR. CHUBBS:
A. For the second application, the second project, we have a contribution in aid of construction policy and when customers, you know, are adding to facilities, when customers are connecting to the grid, we look at what is the cost to connect that customer to the grid and we look at the revenue that we will receive from that customer through the additional sales as

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well. And for MUN substation, converting their boilers from oil to electric is a significant increase in electricity consumption, an increase in sales and through our CIC application, which was approved by the Board, it was determined that there was no requirement for a contribution from the university because of the increased revenue from Memorial University would essentially pay for the cost of that substation expansion. That's the same as we treat, you know, any other general service customers or residential customers for that matter. So, if you're connecting to the grid and let's say for example, you know, we need to build five kilometres of line to hook one home to the grid, we would expect that we wouldn't collect enough revenue potentially from that home to pay for that large line extension. So that cost would be incurred by the customer. Whereas if you're putting a new home in a subdivision or near existing infrastructure and we've only got to put in a pole or two to connect you, under our CIC

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policy, we look at the revenue we're going to collect and what the cost of that pole is or those poles and if it's offsetting, then there is no contribution from the customer. So, this is a longstanding policy we've had in place at Newfoundland Power for a lot of years and again, you know, for MUN, that was reviewed by the Board and approved by the Board.

FITZGERALD, KC:

Q. I realize that, but in this case, this is more than a line. This is a 3.3-million-dollar capital project that was not paid for by the customer for the reasons that you just explained and was there any – so, was there a study done -

MR. O'BRIEN:

Q. Mr. Chair, I'm not certain that's what the evidence was. The additional revenue paid for it. So, to say it is not paid by the customer, Mr. Chubbs didn't say that.

CHAIRMAN:

Q. Mr. Chubbs can clarify his response on that if he wants to.

FITZGERALD, KC:

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Q. Right.

CHAIRMAN:

Q. Whether he agrees or not with Mr. Fitzgerald's statement.

MR. CHUBBS:

A. Yes. So again, you know, the customer, in terms of Memorial University, our sales to Memorial University are going to increase. We're going to collect from Memorial University more revenue over the life of that asset, during the life of that asset, that offsets the initial capital investment to put the substation in place. So, because of that, there's no requirement for Memorial University to pay a contribution to the substation. Now, had the expansion, you know, been – the cost been higher or their consumption being lower, right, in that analysis, there may have been a contribution, maybe a partial contribution. So, it really depends on what the cost of the expansion is and it depends on the increased revenue you're going to get from that customer. So, that's how our CIC policy works and that's – again, that's a

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longstanding policy and this one was reviewed by the Board, approved by the Board and determined that the increased revenue from Memorial University more than offset the cost to build the substation.

FITZGERALD, KC:

Q. Is that based on the condition precent that the boilers actually get trans – swapped out or is that – or I should ask this. Do you know if the conversion has taken place yet?

MR. CHUBBS:

A. I know the project is ongoing. I know the completion date has moved a few times. It's been delayed but they're in the midst of completing the project, yes.

FITZGERALD, KC:

Q. Right. So, there is no cash flowing yet to pay for the 3.3, if you want to look at it that way. The capital cost has been incurred of the 3.3. There's no revenue yet that could be identified that's flowing back to pay for the 3.3 yet?

MR. CHUBBS:

A. Yeah, the boilers are not installed yet. The project's not completed yet.

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FITZGERALD, KC:

Q. Is that – does that comply with the CIAC? I mean, it sounds to me – I mean a little bit, maybe not speculative, but you're hoping that this transfer will take – you know, that there won't be a change in the administration, won't be a change in the policy of MUN not to do the conversion. Because if they, that third party does that decision – makes that decision, then you're not getting the same revenue to pay for the 3.3 million bucks. Would you agree?

(10:15 a.m.)

MR. CHUBBS:

A. I mean, there's a certain set of assumptions that you have to put in for a project like that. I mean, you know, we're working – our engineers are working with MUN's engineers to understand what the demand, what the consumption of those boilers are going to be over their life and it's been fully, you know, reviewed by our engineering team. We're confident that the sales are what they're going to be. The demands on the system is what it's going to be and we're

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certainly comfortable with all that. In terms of timing of the project, you know, Memorial University would be subject to the same supply chain issues that we're seeing, but we're only talking about, you know, a year or two on what's a 50-year asset at the end of the day. So, you know, we are certainly comfortable with the set of assumptions. We know the project is ongoing and expected to be complete within the next year or so.

FITZGERALD, KC:

Q. Sure. But I guess the answer to the question would be that that is out of your control somewhat when the revenue starts flowing as a result of the boiler transfer. It's a third party has control of that situation, not Newfoundland Power, correct?

MR. CHUBBS:

A. Yes, I would agree with that, yes.

FITZGERALD, KC:

Q. And we would also, I guess, in your experience you've seen projects, you know, some projects get mothballed, some projects don't go ahead because of funding problems.

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Would you agree with that?

MR. CHUBBS:

A. Yes, some projects do get mothballed at times, yes.

FITZGERALD, KC:

Q. Okay. So, there is some risk, if you will, that the rates from the consumption from MUN will not be enough to cover for this – or to pay for the Long Pond substation? If I could put it another way, you are taking a risk?

MR. CHUBBS:

A. Again, if we look at – we get the appropriate guarantees, I think, from the customer that these projects are going ahead and in terms of risks, you know, Mr. Comerford is certainly well tuned to speak about MUN. He was very close to the CIAC calculation and the agreement with the university and I can't speak to it, so he might be better to speak to anything that's built into that contract, in terms of if the load doesn't materialize, whether that customer – that cost gets passed onto that customer. So, I would think Mr. Comerford

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could address that.

FITZGERALD, KC:

Q. Okay. So, we do know though that the 3.3 or the Long Pond substation, the total cost, and I'm going to throw this number at you, you can dispute it, I think 9.3 million dollars was spent on the Long Pond substations between the two? Would that be in the ballpark?

MR. CHUBBS:

A. Two substations?

FITZGERALD, KC:

Q. Well, sorry, there was the 4.6 for the Long Pond substation. There's 3.3 for the replacement transformer at Long Pond and there's 1.6 for the MUN T-2 replacement.

MR. CHUBBS:

A. Yeah, so MUN T-2, which is at MUN substation, not Long Pond substation.

FITZGERALD, KC:

Q. Okay, sorry. So, that totals 9.3?

MR. CHUBBS:

A. That sounds accurate, yes.

FITZGERALD, KC:

Q. Right. And that amount of course is in

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Newfoundland Power's rate base?

MR. CHUBBS:

A. It would be in Newfoundland Power's rate base but the offsetting contribution for the redundant facility, the Long Pond project, so the 4.6 would be a negative impact on the rate base. So that would be taken out. So, it would really be the second transformer at Long Pond and of course, the replacement of the transformer at MUN that would be fully reflected in rate base. I'm getting into accounting matters here now, so I may be a little off here, but this is how I understand it, right.

FITZGERALD, KC:

Q. Okay. So, back out the 4.6 from what I – the 9.3 number that I threw at you, which would leave whatever that math, but there is a component, the substations are in fact in rate base?

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. Right.

MR. CHUBBS:

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A. I would agree with that.
FITZGERALD, KC:
Q. And if MUN had to pay for those themselves, then obviously they would not be in rate base.
MR. CHUBBS:
A. That's correct.
FITZGERALD, KC:
Q. Just you mentioned the connection policy. Can you just give us a high-level view of what happens – you know, walk us through the process of, you know, when Newfoundland Power takes on a new general – large general service customer. Do you make a determination where to connect, what the costs are and what's to be borne by the customer?
MR. CHUBBS:
A. Yeah. I mean, if a new large general service customer is looking to connect to our system, you know, they reach out to Newfoundland Power typically through our contact centre. They're put in contact with typically the technologist who's responsible for that area. That technologist would

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complete a site visit, understand the infrastructure that's there, what – they meet with the customer, try to understand their load, what their demands are going to look like, their connected capacity, you know, what their scheduling is in terms of requiring the new load to be construction power or not, when you're going to need full power, and then that technologist would complete typically a design to connect that customer to the electricity system. If there are upstream impacts, so you know, so far we've been talking about the site, you know, but if there are upstream impacts, you know, our engineering team, our planning team would look at that to understand okay, is this going to exceed the capacity of the line further up or, you know, have impacts on the substation or transmission network. We're getting into very large loads here now. And they would engage our engineering team, if necessary. You know, in terms of completing the design, I mean, we're looking for the least cost approach to connect that customer to the grid. So, what is the

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nearest, straightest route that we can get that customer connected, and you know, if we're getting into – in terms of connect the customers, you're looking at then getting into the CIC policy, right. And so, then if we have the design, we would understand what the costs are to connect that customer to the grid and in understanding the customer's load and demand and we're likely looking at other similar customers as well to help understand that, and we determine what their revenue would be from those customers going forward and, you know, that's where the CIAC policy kicks in, right, if it's a service that large. So, that would be reviewed and if necessary, file with the Board and approved with the Board if there's CIC required, and that generally is how the process works.
FITZGERALD, KC:
Q. Okay. Thanks for that. The connection policy itself, is that in a document that's in evidence or is that internal to your department?
MR. CHUBBS:

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A. The CIC policy, I'm fairly certain it's a publicly available document. I'm not sure that it's on the record.
FITZGERALD, KC:
Q. Okay. So that it's one and the same. Your connection policy is the CIAC?
MR. CHUBBS:
A. Yes, that's what we're into, yes.
FITZGERALD, KC:
Q. They're identical?
MR. CHUBBS:
A. Contribution in aid of construction, CIAC. Sorry, didn't clarify that. I should also add that that's something that's routinely reviewed and updated based on updated costs as well. So, we see cost for poles or conductor, things like that, to change over time. That is updated routinely.
MR. O'BRIEN:
Q. Mr. Fitzgerald, I think it is on the record in response to one of your – I think it's CA-NP-134.
FITZGERALD, KC:
Q. Sure. I just wanted to confirm that we're talking about the same thing, the connection

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policy that Mr. -
MR. O'BRIEN:
Q. That's fair.
FITZGERALD, KC:
Q. - Chubbs just went through reflects – And I guess, while we're on the MUN issue, if we can go to CA-NP-255, Attachment A, please? Thank you. And if we scroll down a little bit further. Okay. Here we have the – and I don't know if we can capture the whole page, top of the page. Okay, you almost had it there. Okay. So, this confirms -- this is supplying feeder or transmission line. Then we have, to the left, that column, left-hand column, supplying substation and then it has MUN LPD, feeder code not applicable, designation 1-12L, 14L, 36L, voltage 66. Feeder capacity, supplying transmission, and the far right-hand column, customer served by substation one. So, that's confirmed?
MR. CHUBBS:
A. Yes, that's confirmed.
FITZGERALD, KC:
Q. If we just go to page 32 and 33 of the

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rebuttal evidence, down at line 19. You're on the right page?
MS. GLYNN:
Q. I think it was page 32.
FITZGERALD, KC:
Q. 32, I'm sorry, line 19. And I think we've been through this a little bit already, Mr. Chubbs, but the rebuttal evidence says, "Mr. Bowman does not acknowledge that a contribution was not required from MUN since the cost of supplying the university, including the cost associated with assets that only benefit MUN, are recovered through rates". And so, are all the costs going to be recovered through rates?
MR. CHUBBS:
A. I think it's best for Mr. Comerford to get into the details on which costs hit rates and which don't. As I mentioned, you know, there's – we've got multiple things going on there at Memorial University. You know, the redundant facility, which was fully contributed by Memorial, is there. So, that wouldn't impact rates. Then you have the expansion of Long Pond substation for the

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addition of the boilers. There was no requirement for an upfront contribution because the cost of that will be recovered from rates and you know, the expansion or the replacement of the failed MUN T-2 transformer, you know, is a unit that was serving the university that failed and needs to be replaced and that would be recovered through rates collected from that general service category. So, as I said, there's a few things happening there, and Mr. Comerford certainly can speak to the details on it.
FITZGERALD, KC:
Q. Okay. Well, we'll defer it to Mr. Comerford. If we can go for a second to PUB-NP-105? Here the question was: "was the reasonableness of the rate paid by MUN evaluated in the previous rate design reviewed? If yes, what was the conclusion?" The answer is: "yes, Newfoundland Power's current customer rate reflects – rates reflect the recommendations of the retail rate review conducted in 2010." So, that's 14 years ago. How can we be confident that

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the cost of supply to MUN is recovered in rates when there hasn't been an assessment in 14 years?
(10:30 a.m.)
MR. CHUBBS:
A. So, I think what we're pointing out here really is that we've got some big changes happening at Memorial University now that are currently ongoing. The fact that MUN is adding boilers, expanding the substation, you know, the revenue from Memorial University will change significantly in the next year or so when that project comes online, and that will be the appropriate time to look at MUN and MUN's rate and whether we need to do something differently. The last time this was reviewed in 2010, you know, we're looking at the cost to service MUN compared to that rate 2.4 category and we're looking at the revenue we collect through that from rate 2.4 customers and the revenue we collect from Memorial University and they were generally in line, you know. And at that time, it was deemed appropriate that Memorial University continue to be a

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rate 2.4 customer. I think with the upcoming changes, MUN expanding, you know, there's potential there that they could become a curtailable customer. So, we need to consider that as well going forward. That is something that we want to review and the appropriate time is to do that review prior to our next general rate application when we have certainty on all this.

FITZGERALD, KC:

Q. Sure. And you mentioned that there's a lot of changes coming and it's growing. Is MUN going to come to the point that they're actually a distributor of electricity?

MR. CHUBBS:

A. I'm not sure I could speculate on that. I mean, you know, Memorial University has been a customer of Newfoundland Power for decades, right. I think that the arrangement works well. I think that – I can't necessarily see how Memorial University would become a distributor and what the benefit would be there at this point.

FITZGERALD, KC:

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Q. I guess they have multiple physical plants. Health Science Centre for one, I believe. Would you agree? I think that's one of their – not say their customers, but one of the physical plants to which they provide electricity?

MR. CHUBBS:

A. Yeah, I mean, all – you know, you got the full campus, right, that's being supplied from MUN substation and Long Pond substation, you know, as a customer of Newfoundland Power in rate 2.4 category. So, it's been that way for a long time. Again, they've been that way for decades. We looked at it in 2010. They still fit that rate 2.4 category in terms of the revenues we collect from Memorial University and the cost that we incur to serve them. So, continue to be appropriate. Right now, it's something we'll look at again, whether we need to separate them out into a class of their own potentially, you know, that has a different rate. But that's something to be determined once we fully understand the changes in their demand, energy consumption.

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Again, whether they could potentially be a curtailable customer for us. So, all that kind of needs to be factored in before we would pull that out. I don't necessarily see, you know, getting into distribution at the university, how that kind of makes sense.

FITZGERALD, KC:

Q. Well, I'm just--you know, when you think it through, I suppose, if MUN has its own substation, there's one customer, they're distributing power. For example, they distribute power again to the Health Science Centre. If there was a failure in supply, whose responsibility is it? Is it MUN's, or is Newfoundland Power's?

MR. CHUBBS:

A. MUN currently owns the distribution within the campus, right.

FITZGERALD, KC:

Q. Right.

MR. CHUBBS:

A. So, our service point leads up to the substation. So, any failure of a distribution cable, or a piece of equipment,

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or a switch within their facility, are their responsibilities, not the responsibility of Newfoundland Power.

FITZGERALD, KC:

Q. Well, it's almost to the point that, you know, of that size, you know, should the Public Utilities Board regulate their distribution of power to, for example, the Health Science Centre or other physical plants on the campus. You have no responsibility beyond their distribution point, then obviously, or not obviously, but I would think that there would be no legal liability either, but then that's the Wild West. There is a distributor there contributing, or distributing, electricity with no regulation.

MR. CHUBBS:

A. We have many commercial customers. We serve them up to the point of, you know, the metering of that facility. They have buildings that are distributing electricity throughout different floors, or maybe even different buildings, on the same site. So,

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that would be a routine scenario. These costs aren't incurred by Newfoundland Power's customers. They're not passed on to Newfoundland Power's customers. So, what's on the other side of that meter really doesn't impact rates for Newfoundland Power's customers, or rates in this Province, that I can see. So, I don't quite understand why the regulator would need to step in there and regulate the University. You know, I'm not really following where you're going with it, but -

FITZGERALD, KC:

Q. Sure. Well, if that's your answer. Let's move on to another topic, page 40 of the rebuttal evidence. So, at the bottom of the page there it says, "Since the frequency of Newfoundland Power's customer outages is consistent with the Canadian average, Mr. Bowman's recommendation implies that the company should slow its response to customer outages." Mr. Bowman didn't actually say that, would you agree?

MR. CHUBBS:

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A. I'll take your word on it that it's not in his evidence.

FITZGERALD, KC:

Q. Okay. If I could characterize his evidence, and if you don't accept you'll tell me, but isn't Mr. Bowman saying that Newfoundland Power should stop spending money to target a safety level that is 40 percent better than the Canadian average when it doesn't have the evidence that the customers are willing to pay for safety levels that are 40 percent better than Canadian average? That's his point, would you agree?

MR. CHUBBS:

A. I guess.

FITZGERALD, KC:

Q. On page 41, line 1, the statement here is, "Newfoundland Power does not seek overall reliability and service improvements, nor is its capital spending driven by overall reliability improvements." And then further it says, "Newfoundland Power's capital planning process"--I'm at line 6 here now, "Is a deliberate effort to balance the cost and liability of service provided to customers." So, can you maybe expand on that, explain how Newfoundland Power's capital spending is not driven by overall reliability improvements, at the same time your capital planning process is a deliberate effort to balance the cost and reliability of service provided to customers?

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MR. CHUBBS:

A. The way Newfoundland Power looks at it, and our experience in terms of cost and reliability, is that a reliable system is an efficient system. When you look at Newfoundland Power's experience over the last 20 years, our reliability 20 years ago was worse than it is today, you know, twice as--customers experience outages twice as much as they do today.

Over that 20 years we've deliberately focused, I'll say the first half of that 20 years, we focused on improving reliable service to customers. We brought in a preventative maintenance program, integrated that into our generation substation transmission and distribution processes through inspections and repairing things as they approached end of life, and we reached a level where we were comfortable that we were doing the right things in terms of overall reliability. You know, our concern with the implication, or the--I should say the recommendation that we target reliability that's worse. We don't see, based on our experience, how that reduces cost.

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So, when we look at how we achieve the reliability that we've experienced today, I mentioned this in my direct, it breaks down into three areas, right. It's the standards that we build the electricity system to, and it is the maintenance practices that we have in place to maintain the system, and then it's our operational response, how quick we actually respond when things fail.

So, when there's a suggestion that we need to reduce reliability to our customers, when you practically think about how am I

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going to accomplish that--well, if we go to number one, you know, you're suggesting that we build to a lower standard, right. We build to national standards that specifically are designed to account for the weather, severe weather that we have in Newfoundland and Labrador. So, we're suggesting now we build something--to something that's a lower standard that's going to fail when we have these severe weather conditions, and then you have to rebuild. So, yeah, could you build it more cheaply upfront by building a substandard line? You could do that, but it's going to fail and you're going to build it again. It's not going to save any cost. And the suggestion is at this time, when we're thinking about looking forward and climate change impacts, impacts on the grid, we're wondering if we're building strong enough, you know. And CSA, the Canadian Standards Association are looking at that, you know, our utilities and are our standards sufficient to meet future storms, right, and

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that's something that we're all--all utilities are trying to understand. So, I don't see how that reduces cost. I don't see, you know, how I could even propose building a substandard line anyway.

So, then we go to number two, which is how we maintain the system. And we maintain the system in a manner that gets the maximum life out of our assets. We inspect our distribution lines, our transmission lines, our substations, on a routine basis. We come back on a regular cycle. We look at the assets and we say is that going to last another year, or is this something that I need to replace within the next year or so.

So, if we're talking about trying to reduce cost by doing less maintenance--so, you know, the way you accomplish that is well, I can stop inspecting lines, and I guess I could save some money by not having people out looking at our substations and our lines.

You know, let's put safety aside there for a second, let's say we do that, but

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things are still going to fail, right. They're going to fail, but they're going to fail in an unplanned fashion, right. They're going to fail in a storm. They're going to fail in the middle of the night. You're going to be getting crews out of bed to respond. You're going to be paying them double time to respond. So, it's only going to drive costs up.

The way we do it today is we inspect our lines, we manage our assets, we try to determine when that piece of equipment is going to fail, and we try to replace it as close to before that point as we can practically speaking, right, in a planned fashion. So, you're doing it on a regular time, minimizing the impact on customers, and at the lowest possible cost.

So, then getting to the recommendation of, well, how do I reduce my reliability 40 percent. Then you get to the third piece, which is your response time. So, I guess if we want to reduce reliability to customers, well, when they call in and say my power is

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out, I guess we can, you know, wait an hour and then send a crew, and that will reduce our average duration of outages. I don't see how that saves costs. It certainly--it's certainly not good customer service, but I don't see how that reduces cost to any great degree.

So, when I see the recommendation of, you know, targeting worse reliability performance than we currently experience today, I see only cost pressure, increase costs, or reduce service to customers, both really. So, we have--you know, we have a hard time getting to that point, you know. We think what we do today in terms of managing our electricity system is appropriate, it's reasonable. It's providing good outcomes to customers, and at the end of the day it least cost, right. If you're managing that asset to the--as close as you can to before it fails, that is the least cost way to manage the electricity system.

(10:45 a.m.)

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FITZGERALD, KC:
Q. Okay. Thanks for that full answer. I guess the--we're maybe talking semantics here as about targeting less reliability as opposed to, you know, maintaining this 40 percent better than Canadian average spot where we find ourselves now after we've paid for this. So, on page 41 it's stated that, if I can take you there for a second, at line 12 it says, "Newfoundland Power employees that are responsible for responding to customer outages are also responsible for maintaining the integrity of the electrical system." So, if the Board ordered Newfoundland Power to reduce the cost of its operating budget, would there be an impact on saving?
MR. CHUBBS:
A. Well, it would depend on what cost you're talking about. I mean, if you're talking about reducing cost that we incurred to inspect our distribution lines, or transmission lines, it absolutely would affect saving. If you're talking about not responding to equipment that's failed in the

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field, I mean, absolutely that would affect our saving.
FITZGERALD, KC:
Q. Well, you know, just operating costs, and not particularly your department but, you know, if it was asked--the Board ordered Newfoundland Power to reduce the cost of its operating budget generally, I mean, is there going to be a reduction in saving?
MR. CHUBBS:
A. Again, we're hypothetical here. I would assume there would be some direction or understanding from the Board on where they felt our costs weren't appropriate. You know, if we're getting into--we've talked about the operational cost. If you're getting into customer service costs--so, are we talking about, you know, not answering the phones when customers call in, like having reduced staff at our contact centre so customers can't reach us, or not having the technologies that they can't report outages, you know, appropriately, or not having technology so customers can see that

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they're being impacted by an outage or when the restoration time is? I mean, all of these costs, you know, are related to the reliability and the service that we provide to our customers.
FITZGERALD, KC:
Q. So, would you agree that there is an incremental cost associated with maintaining current levels of reliability?
MR. CHUBBS:
A. In our, Newfoundland Power's, view the reliability of the service we provide to our customers is least cost. That's the way we look at it. Our experience has been over the last two decades that we've been able to improve reliability that we provide to our customers, while at the same time managing our operating cost and keeping them below inflationary levels. So, in our view, a reliable system is an efficient system. Now, that's not--that doesn't go on forever, right. You can't just keep adding and improving reliability and cost goes down to nothing.

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We all understand that if we wanted to really improve reliability, and this is kind of where we feel we are now--if we're looking for continual improvements on reliability, you're probably adding cost, right. You're probably--we're talking about putting your system underground, or having two feeders every—you know, two feeders everywhere, redundant equipment everywhere. We're not--certainly not there.
We feel like the point where we are right now provides reasonable reliability to our customers, and our customer satisfaction scores tell us that they feel that the reliability received is appropriate, and we feel that the least cost. We feel our approach to managing the reliability of the electricity system is least cost for our customers.
FITZGERALD, KC:
Q. There's a comment made here if we can go to page 43 in the rebuttal evidence, and it's again critical of Mr. Bowman's evidence, and I would suggest perhaps mischaracterizing

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what he is saying, but at page 5, or line 5, I'm sorry, it says, "Intentionally allowing system reliability to degrade." So, this gets back to your comment about ethics, and you couldn't do that in good conscientious, certain things, you know, but the intention--it's kind of a strong word there. If the Board were to order Newfoundland Power to reduce spending on operating costs, you know, wouldn't the reduction of spending on operating costs, you know, simply--it's not a degrading of the reliability, it's just a signal, or an indication, or incentive, for Newfoundland Power to become more efficient with what they have to spend on reliability?

MR. CHUBBS:

A. You know, throughout our evidence there's many examples of how Newfoundland Power has improved its overall operating efficiency. We've done that through maintaining the system reliably. We've done that through the use of technology to allow us to operate more efficiently. You know, what we're getting at here when we're talking targeting

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worse reliability, we're getting into areas in that in our view would increase cost, right. It would result in more unplanned failures to our customers, and again, more occasions where our crews have to respond after hours, overnight, in the middle of storms, to things that fail rather than responding in a planned fashion, right, in a least cost manner.

So, you know, it's difficult to see how cutting operating cost, or cutting investment in the system to maintain reliability, leads to lower cost at the end of the day. I just can't see it in terms of how we operate our electricity system. We feel it's providing good value to our customers. We feel that, you know, that's indicated from our customers, from our customer surveys, and overall the costs we've put forward are reasonable and they're appropriate.

FITZGERALD, KC:

Q. But we're talking maybe of two different things. You know, what I'm suggesting is

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the 40 percent above average reliability that Newfoundland Power enjoys, or perhaps you might argue that the customers enjoy, you're suggesting that if that was degraded, and that's your word, or if that--you know, if that was to not be at that level, say 20 percent, or even down to five percent of higher than the Canadian average, then this would cost, this would not be least cost. There would be cost affects of that. But your--do you have any, you know, empirical evidence, you know, regarding your peers' experience, other utilities who aren't enjoying 40 percent reliability? Are they somehow being irresponsible and costing their customers money by keeping reliability at an average as opposed to an over average amount?

MR. CHUBBS:

A. Well, I mean, it's important to keep in mind that when we talk about the Canadian average, you know, this is the Electricity Canada region 2 utilities, so utilities with an urban/rural mix, which is what

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Newfoundland Power has. There's 16 or 18 utilities in that. The last time I looked at it half were above or so, half were below. Not every utility is experiencing the same number and Newfoundland Power's here. There's a range of experiences in there, and it's related to a lot of things, right. It's related to the condition of their electricity systems and how they maintain them, all that's part of it. You know, it's related to the environmental conditions that they're under, different jurisdictions.

So, there's a lot of factors that are at play in that Canadian average number. So, because we're 40 better we're not outlier certainly. We don't see it necessarily as a--that's our position among the group.

Even the urban/rural mix, for example, you know, some utilities, you know, you tip in and get better reliability in urban areas where you can respond a little quicker versus rural areas, right. So, all those

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can--so, it's really hard to sit back and look at utility by utility, where they are in terms of overall cost and overall reliability.

Again, the way we view it is we are building our system to the appropriate standards they should be built to. We're maintaining the system, you know, using utility best practice. This was reviewed by Liberty on behalf of the Board. It determined that our maintenance practices were appropriate, and then we respond effectively. And I think another thing to point out, and it's very important to point out, is the reliability number we're talking about, which is SAIDI, right, your average duration of customer outages. There's two parts that make that up, right. It is how frequent a customer experiences an outage, and then how long that outage, that average outage, occurs, right.

So, last year, for example, our reliability under normal operating conditions was 2.6 hours. That's what our

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average customer with Newfoundland Power experienced, was 2.6 hours of outage time. That's excluding major storms and any loss of supply. When you break that down, the average customer of Newfoundland Power last year experienced two outages, and the average outage lasted 1.3 hours, right. So, two outages times 1.3 hours gives you 2.6 hours of total outage.

When we compare the frequency, so that two outages that each customer experienced, to the Canadian average, our frequency of outages is actually right in line with Canadian average. So, that tells me our system is holding up as well as the average utility in Canada, right. The difference for Newfoundland Power is the duration of each outage, right, so that 1.3 hours on average that an outage lasts, and that's the operational response piece, right.

And there's a couple of things you can attribute that to. Why is Newfoundland Power 40 percent better in that category, right? So, we're not talking the system,

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we're talking response. And, you know, for me largely it's cultural, right. Our employees, when the power is out, they respond, right, that's what they do. And it's been, you know, engrained in the culture at Newfoundland Power, certainly for my entire career, that when the power is out the customer--our crews go. They get up and go and they respond, and they respond very effectively, and the folks who are managing that response, specifically like for the large storms, do a really good job managing that response.

And over time as well, another component of that is the technology we've put around the management of that response time. We've added over the decade or so technologies, you know, our geographical information system, which gives us the location of our assets and our crews, you know, on the screen for our dispatchers and our control centre to get, you know, the nearest crew to the outages as quick as possible so they know exactly where their

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crews are.

We've built in--we got a new Edge Management system that we've added in the last five years that predicts the location of outages. So, when we get calls from customers it--you know, as those calls are coming in, our Edge Management system, which understands the connectivity of the electricity system, and it says, well, I'm getting three or four calls over here. It looks like this neighbourhood is out, or this transformer is out. I'm getting more calls over here. Okay, no, that looks more like this tap, this line, is out, or this neighbourhood is out, and it predicts where the trouble is rather than just having a list of outage reports from customers.

So, that allows us to understand what the impact is on the grid, and it also allows us to predict which other customers are impacted by having reported the outage. So, now when they call in our technology in our contact centre, when it picks up, it right away knows that you are being affected

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by an outage right now, right, and we can tell that customer--you know, they can go through our interactive voice recording system and all that, and we can say we're aware of your outage. So, they don't need to talk to a contact centre agent, right, as well. So, we've put a lot of technology around our operational response, and that is the differentiator for Newfoundland Power, not the system necessarily.

(11:00 a.m.)

FITZGERALD, KC:

Q. Okay. I don't mean to cut you off there, but I guess the question is, and I understand what you've just said, but you would have us believe that by maintaining a 40 percent safety above Canadian average that is actually saving consumers money. Even though there's a capital cost involved there, and a huge labour cost as you--I think you sort of indicated, that somehow this 40 percent is actually saving us money. Is that what you're suggesting?

MR. CHUBBS:

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A. I can understand what you're getting at, right. There is a cost to maintaining the electricity system, and I agree with you there. I think where the disconnect is is that in our view this is the least cost way to go about it. If you're building your line to the standard it needs to be built to, and you're maintaining the system to get the maximum life out of that asset, right, so that you replace it in a planned fashion on regular time, and not allow it to fail so that you're replacing it on overtime, after hours, calling crews out of bed, you know, to go do that, then that is the least cost way to go about maintaining the system, right. So -

FITZGERALD, KC:

Q. Okay. Sorry, I don't mean to cut you off again but we're getting close to the break. I have one more question on this topic if I might. You did mention that you believe that this is also--this 40 percent above average safety rate is aligned with what customer surveys have communicated to

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Newfoundland Power, but we do know, or correct me if I'm wrong, that no customer of Newfoundland Power has ever been asked if they would--if they would be okay with a lesser response time for an outage if in fact that reflected in a lower power bill. You mentioned earlier about the culture of Newfoundland response, or employees' response. We know, of course, they're not volunteering this, this is all overtime work. So, it is a cost to actually, you know, get the line back up immediately, but we do know that it's never been--we understand that the surveys are geared toward asking are people satisfied with Newfoundland Power's service, and it's a scale and they say yes or no, but they've never been asked whether in fact they would be okay with a lesser duration, or a longer duration, outage if it would save them money. We know that question has never been asked, correct?

MR. CHUBBS:

A. I just want to correct what you mentioned

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there about it's all overtime, right. I mean -

FITZGERALD, KC:

Q. Sorry, okay.

MR. CHUBBS:

A. I mean, our approach is to minimize the amount of overtime that is involved in responding to customer outages, right. In terms of the survey--I mean, this has been asked many times, and it's been asked as part of our capital budget, and it's been asked here as well. You know, the premise of the survey, and I think this is what I started with, I think is where the--that the question that you're asking is where the problem is, right. This idea that it's a trade off that we can turn the dial on reliability down to save cost, and I walked through earlier--you know, when you think practically about how you actually reduce reliability for customers, it looks like increase cost, you know. It looks like again building substandard lines, or not maintaining your lines, and in responding

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inefficient, unplanned, fashion at higher cost. So, I think that, you know, to go and ask customers would you like to experience less, a less reliable service at a lower cost is a false premise, right, because I'm not sure that that's something that Newfoundland Power could deliver on. We feel that we're providing an appropriate level of reliability for our customers, and that is least cost. That's our view.

FITZGERALD, KC:

Q. Thanks, Mr. Chubbs. I think you and I are testing the patience of the Board here now, so I guess we should probably break.

CHAIR:

Q. Thank you. We'll recess.

(BREAK – 11:04 a.m.)

(RESUME – 11:36 a.m.)

CHAIR:

Q. Thank you, Mr. Fitzgerald.

FITZGERALD, KC:

Q. Thank you, Mr. Chairman. Just to change the topics really quickly, Mr. Chubbs, on the issue of operating costs and executive

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compensation, if we could go to the Korn Ferry report, please, at page 9. And, Mr. Chubbs, your salary is demonstrated there for all to see. Your base salary is there at $345,000.00 and there's a target of 65750, and the total target remuneration is 712. Are you able to tell us what portion of that, assuming that you make that, what portion on a percentage basis is paid by the consumer?

MR. CHUBBS:

A. The way our compensation works, so my base salary of 345 would be included in regulated costs. We have a short-term and a long-term incentive which is included in the total here, but only the short-term incentive up to 100 percent of that amount is included in regulated costs. Anything above 100 percent on the short-term incentive is non-regulated and the long-term component of it is also non-reg—it's not incurred by customers.

FITZGERALD, KC:

Q. Okay, so it's not obvious to me, then, if I look at the 712 figure of the annual salary, let's assume that that target is met, are

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you able to sort of tell me or the Board, I guess, you know, what portion of that would you expect, rather than, you know, STIs in the long-term, reasonably what would you expect of that 712 would be non-regulated?

MR. CHUBBS:

A. Non-regulated?

FITZGERALD, KC:

Q. Non-regulated. Well it doesn't matter, I mean whichever way you answer it.

MR. CHUBBS:

A. Yeah, I mean a rough calculation probably 500 would be regulated, the other 200 would be non-regulated.

FITZGERALD, KC:

Q. Okay, thank you. And just going back this morning, your testimony regarding the load research study and the ordering of the meters that are on backorder, I understand those are probably smart meters, is that correct, is that what we're waiting for?

MR. CHUBBS:

A. Yes, those meters would be capable, smart meters are providing that 15 minute interval data, so our reading on the customer's

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premise every 15 minutes to give you that granularity of data that you would need for a load research study.

FITZGERALD, KC:

Q. Okay, and did you say, I know you deferred some questions to Mr. Comerford, but would he know when it was that following the agreement on the load research study, would he know when it was that, when these meters were ordered by Newfoundland Power?

MR. CHUBBS:

A. Yes, Mr. Comerford certainly could speak to how that load research study has kind of unfolded in terms of all aspect of, you know, seeking, I'll say developing a framework, seeking the appropriate partners and consultants who can complete that work for us, determine the number and the type of meters that we would have needed and then, of course, when the meters were ordered and when we understood what the delivery times would be, he can give you the full details on that.

FITZGERALD, KC:

Q. Okay. In the meantime, it's your

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department, can I ask for an undertaking that you provide to us the date that the smart meters were ordered?
MR. CHUBBS:
A. Okay, yes.
MS. GLYNN:
Q. That would be Undertaking No. 8.
FITZGERALD, KC:
Q. Just on the issue of smart meters, Mr. Bowman, in his evidence, has put forward some statistics regarding smart meters and I'm just going to ask you about them, whether you agree or disagree. One of the statements that he has made is that over 70 percent of Canadian households and businesses currently use smart meters, would you agree or disagree?
MR. CHUBBS:
A. I haven't looked into the numbers myself, I would tend to agree that the majority of meters out there are smart meters.
FITZGERALD, KC:
Q. Okay, there's another statistic that was mentioned in Mr. Bowman's evidence about a forecast that 94 percent of Canadian

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households and businesses will have smart meters by 2027. Would you take issue with that projection?
MR. CHUBBS:
A. No, I would not.
FITZGERALD, KC:
Q. Okay, and also we have an RFI and I don't know if we have to go there, just ask you the question, but the reference is CA-NP-034, footnote No. 5. And the quote is—and I guess we could go there, I suppose, to be fair, CA-NP-034, footnote 5. It says here, "In Canada"—maybe we should scroll up to the reference of the footnote, right so now down to the footnote it says, "AMI technology has been mandated by legislation in British Columbia and Ontario." You agree?
MR. CHUBBS:
A. Yes, I would agree.
FITZGERALD, KC:
Q. And in footnote No. 7 on the same RFI there is a statement that "Nova Scotia Power received approval for an 133 million smart meter project", so you would agree with that?

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MR. CHUBBS:
A. Yes, I would agree with that.
FITZGERALD, KC:
Q. And further "New Brunswick Power received approval for 110 million dollar smart meter project before the Federal New Brunswick Energy and Utilities Board", do you agree?
MR. CHUBBS:
A. Yes, I agree.
FITZGERALD, KC:
Q. And at paragraph C of the same RFI, line 4 of this page, if you could scroll down and this is Newfoundland Power saying, "The benefits of AMI technology can include the ability of remotely read meters, automatic outage detection and management, the ability to remotely connect or disconnect service to customers, monitoring power quality and implementation of the many responsive programs, such as Time-Of-Use rates, enablement of distributed energy generation, the ability to provide customers personalized energy saving tips and recommendations." So that is the information that we have, those are the

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advantages of smart meters, correct?
MR. CHUBBS:
A. Yes, that's correct.
FITZGERALD, KC:
Q. If we could go for a moment to PUB-CA-26B, I'm not sure if we have the right –
(11:45 a.m.)
BROWNE, KC:
Q. It's A, you said B.
FIZGERALD, KC:
Q. Sorry, if you could just scroll through that RFI, please, for me. A little further, please. I'm looking for the Puget Sound Energy, okay, so footnote No. 5, if you could open that please? The executive summary, and so what you'll see here, the quote "Why are we upgrading our meters?" And it says here, "Our automatic meter reading, AMR system is approaching the end of its projected lifespan." And it says, "Today AMR hardware and software are becoming increasingly obsolete making them difficult to support and maintain." And that's part of the record. If we could go to the same—sorry, you've seen this

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information before?
MR. CHUBBS:
A. No, I haven't read this, but I'm certainly familiar with AMR technology.
FITZGERALD, KC:
Q. Okay, and if we could go to again UBCA-026B which I think is where we are and the BC Hydro footnote No. 6, just scroll down to the executive summary, okay. In the second paragraph there, I don't know if you are with me, Mr. Chubbs? The executive summary, this is from BC Hydro, "BC Hydro's smart metering program is an important foundational step in modernization of BC Hydro's electrical system. Program involves replacing existing customer meters now becoming obsolete with a comprehensive smart metering system." Had you seen that quote before?
MR. CHUBBS:
A. No, I had not.
FITZGERALD, KC:
Q. You know, based on the information that we have, you know, that 70 percent of Canadian households and businesses are currently

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using smart meters, the forecast of 94 percent penetration by 2027, the legislation in Ontario and BC, the New Brunswick Power initiatives and the Nova Scotia Power initiative, the Puget Sound reference of obsolete meters and BC Hydro, would you agree with me that based on the evidence, it likely will be that the smart meter technology is now the metering technology of choice in the industry or very soon will be?
MR. CHUBBS:
A. I would agree that smart meters are, would be most common in the industry and if you want to call that the meter of choice, that's fine.
FITZGERALD, KC:
Q. But Newfoundland Power, as I understand it, there's nothing imminent about any smart meter initiative, is that correct?
MR. CHUBBS:
A. It would depend on what you would call imminent, you know.
FITZGERALD, KC:
Q. We'll say faster than the load research study.

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MR. CHUBBS:
A. Perhaps go back to the Puget Sound page for a second. You know, the first sentence there that their AMRs are approaching end of life and the last sentence, first paragraph, going to be obsolete. The middle sentence there, you know, says that "Puget Sound were one of the first adopters of AMR technology in the late '90s", right, so they were ahead of the time. So I would think that the fact that they are considering their meters obsolete is probably because they were some of the first vintage AMR meters. We started looking at AMR technology in the early 2000s ourselves. We looked at it probably for about five years before we were comfortable with the technology and we understood the efficiencies and the safety implications as well that they provided to our employees. We have not received any indication from our meter supplier who is Itron and I mentioned this morning that they are the largest manufacturer of electricity meters, AMI and AMR and standard digital meters in North America, that AMR is obsolete. We know that

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more utilities are using AMI technology and that's been implemented for many reasons. As we indicated in our response, it's either been legislated or as we're seeing here in our region, in Nova Scotia and New Brunswick, it's been determined to be least cost for customers. When we looked at AMR technology and decided to transition from our standard meter reading, I'll say walk-by meters which was a very inefficient way of doing it, and we did the economic analysis to determine whether AMR technology made sense for Newfoundland Power and would reduce operating costs sufficiently enough that it was least cost total for our customers, we did look at AMI technology at the time and it was clear to us that AMI was not least cost for Newfoundland Power. Our AMR system that we implemented in the period from around 201 to 2017, cost about 25 million dollars to install those meters. And they save, in terms of meter reading labour costs and the fuel and vehicle cost that it took to read all those meters manually every single month, over 2 million

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dollars a year, so when you look at the life of that meter, I think 18 years is the standard life for a meter in our depreciation study, you look at 2 million dollars over 18 years, you get the present value of that and you compare it to 25 million dollars and it was least cost for us to go with AMR meters, right, the drive-by technology. Our meter readers can collect ten times as many readings in a run of a day versus our old approach. AMI also reduces that cost and can effectively get the meter reading costs down to the cost to actually read the meters and collect the readings, you can effectively get that to zero, right. We got 80 percent with AMR, we could have got the other 20 percent if we had gone AMI, but the cost was four times as much. The most was 100 million dollars, right, and when you do that same economic analysis, okay, now I'm saving 2 million a year versus, you know, 2.4 million a year and you look at that over the life of the meter and you get a present value of that, it's not even close to the 100 million dollar

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investment that AMI technology would require. So at that time we determined that AMI was not least cost for our customers and we still firmly believe today that the way we read our meters is least cost.

FITZGERALD, KC:

Q. Yes, but that's the only—that's one advantage of AMR, but you know, it appears that the weight of the evidence is that the industry is turning towards smart readers. You know, the fact that AMR might have been the state of the art technology when this decision was made is one thing, but we're not in 2024, you know, so does the same logic apply, it was least cost then, you know, we do know that Newfoundland Power has had the experience with their customer service computerization which nearly went obsolete, you argued or Newfoundland Power argued was obsolete, but that was a, you know, but there was a huge cost in replacing that but it was almost, the way it was, Newfoundland Power portrayed it, it was a necessary expense. So, you know, catching up with technology, making sure that least

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cost electricity is provided, wouldn't Newfoundland Power be motivated now to change horses, if I could put it that way or adopt AMI?

MR. CHUBBS:

A. I mean AMI and, you know, comparing it to a customer service system is certainly two different things, right, our customer service system was absolutely obsolete, you know, needed to be replaced and so we had to, we had no choice. I think the question here really is about the obsolescence and as I said, we haven't gotten any indication from our supplier or industry that AMR meters are obsolete to the point where we know we need to go out and change all of our meters from AMR to AMI, we have no indication that that's the case and in fact, when we talked to the meter manufacturers, another thing that these, so these meter manufacturers they supply electricity meters but they also do water meters, you know, and they effectively look the same, right, it's just they're measuring water versus electricity. Electricity meters, there's

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value in that more granular data, the 15 minute interval data, so you know, that makes part of your business case in terms of whether you want to shift to AMI, but when it comes to water meters, water meters still rely, for the most part, on that one monthly meter reading, right, so the indication we get from meter manufacturers is AMR technology is going to be around for a long time, you know. It's just the chip of the circuit board that's in the meter, you know, that's communicating the reading, so in our view it isn't an obsolescence issue, but we have continually looked at AMI technology and we looked—sorry –

FITZGERALD, KC:

Q. No, go ahead, finish your thought.

MR. CHUBBS:

A. So we looked at, I looked at it in 2012, we looked at it as part of our last potential study that was completed by Dunsky, this was 2019, so that was part of our electrification conservation demand management plan that we put forward, and when Dunsky looked at it, they looked at it

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from a Time-Of-Use rates perspective, right, and their determination was that it did not pass the economic test that you put around these conservation demand management programs, right, and really what that means is that the cost upfront that you would incur from installing the 100 million dollar AMI technology would not be offset by the benefits that you would get through Time-Of-Use rates and peak shifting, right. And the reason for that was that we had what, we have a very flat load profile in Newfoundland—in our system, so, you know, peak day for Newfoundland Power or for the Island system, you know, we could, the peak could come up in the morning and effectively stay fairly flat, you know, you'd get a bit of a dip in the afternoon, but stay up again the evening, right. What AMI and Time-Of-Use rates do for you is they incent customers to shift their usage from on peak to off peak times. The Dunsky review highlighted the fact that our flat load profile limited how much load you can shift from on peak to off peak, but what they did

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indicate was that with more electrification and more electric vehicles coming on the system, that our system peak would likely shift, potentially shift to an evening peak, like a constant evening peak because everybody would get home at the end of the day, they'll all plug in their electric vehicles and when there's enough electric vehicles in the province, we will have, you know, a regular suppertime peak, you know, on the system. And at that time it would make sense, it may make sense to adopt Time-Of-Use rates to incent customers to charge their vehicle, they can still plug in at 5:00, but they could program it to charge, you know, 9:00, 11:00, whatever you kind of set that around. So you can shift that peak to overnight hours ideally is what you'd be going for. In terms of the cost benefit of that, what we're really talking about is generation, right, so would AMI meters and Time-Of-Use rates shift load from the suppertime peak, that would materialize with more electric vehicles, to an overnight peak to kind of keep the total load flat to a

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point where you could avoid installing generation on the system at some point in the future because of this load growth, right. And so, you know, you'd really need—you're talking about probably having to shift about 50 megawatts of load, right, so you don't have to build a 50 megawatt generator, you know. So when we look at stacking, you know, the potential benefits, there are some of the other benefits that we have highlighted in our response there, we would cut some meter reading cost, the disconnect, reconnect process, you could do that remotely and not manually, but it's really what we are keeping an eye on is that evening suppertime peak when we're going to see that on the system in the future, and will we be able to shift enough load to overnight hours, right.

(12:00 p.m.)

FITZGERALD, KC:

Q. Okay, so you mentioned Dunsky, but I understand that, I mean, Dunsky only studied the benefits of smart meters when it came to load shifting, but there's other benefits,

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as you just mentioned, to smart meters. You know, there's the automatic outage detection, you mentioned remotely connect, disconnect, enablement of distributed energy generation, the ability to provide customers personalized energy savings tips and recommendations and the ability to provide outage and power restoration notifications, so those are other things, benefits of smart meters that I don't believe Dunsky studied, correct?

MR. CHUBBS:

A. That's correct, yes.

FITZGERALD, KC:

Q. Right, and I don't—correct me if I'm wrong, but I don't think Dunksy have rate design experts. I mean, if you don't know, we can check that, but I mean, I didn't believe that that was what they were doing.

MR. CHUBBS:

A. And the reason I paused there is the Dunsky report gets into pretty heavy detail on rate design, what time of day you'd be looking at the rate, you know, a peak rate versus off peak rate. They get into the ratio of, you

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know, what works better, a two to one ratio, you know, you pay 10 cents during off peak and 20 cents on peak or is it 8 cents and 24 cents, three to one ratio, on peak, off peak, so they are pretty detailed in that analysis and how much each type of, you know, scenario would shift—how much load that would shift. So, you know, and they're a pretty significant consulting firm, so I just pause on the comment that they don't have rate experts.

FITZGERALD, KC:

Q. Well we can doublecheck that. But, you know, I guess Dunsky has one view of things, but we also have the weight of all the other evidence of what utilities are doing in Canada and the US re: smart meters, and it looks like Newfoundland Power is isolated in their approach. They are not, there's no initiative, strong initiative, high profile or high priority motivation to get smart meters started. There's nothing going on that's concrete.

MR. CHUBBS:

A. Again, we've looked at smart meters, they

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are not least cost for customers in Newfoundland at this time. We are continually evaluating smart meters and evaluating what the potential benefits in the future may be and when we feel we get to that point where smart meters become least cost for customers, we would certainly be interested in installing smart meters on a go-forward basis, but until we get to that point, it wouldn't be appropriate to incur that significant capital investment at this time without seeing, realizing the benefits that would need to be there for customers. And I think it's also important to point out that, you know, meters have a lifespan, right, so if we were to go to AMI meters today and adopt Time-Of-Use rates today, but there's no benefit to the system or customers for ten years from now, well you effectively use up ten years of that meter and then you're into the tail end of the life of the meter before you've gotten any benefit from it, so we feel like the way things are kind of lining up, our meters where we started our installation in 2012,

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2013, finished it in 2017, 2018, meters last, you know, the expected life is around 18 years, so when we hit that 2030 to 2034 timeframe, which is actually the same timeframe indicated by Dunsky, so it kind of lines up with the life of our current meters, that's the more appropriate time to be considering AMI for our system.

FITZGERALD, KC:

Q. Okay, and I believe what you just stated that this is reflected in the Rebuttal Evidence that's been filed. I was just going to take you to that at page 47, go there quickly, and at line 15 and this is essentially, I believe, what you've just told us, it says, "The implementation of AMI meters at the present time does not facilitate least cost provision of service for a number of reasons." And you go on, so that's the statement, that's the evidence, but can we go to CA-NP-034, scroll down please to paragraph—okay, bottom of the second last page there, it says, "The Company is preparing to model the costs and benefits associated with implementing AMI

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technology." So when I read that, that tells me that there's not been a calculus done yet as to whether AMI is least cost because you don't know, according to this, the study hasn't been done.

MR. CHUBBS:

A. We know the cost of installing AMI meters, it's 100 million dollars plus, potentially. When we look at the benefits and we've looked at the benefits of converting our meter reading technology in the past, there are two operational benefits that we see to go with AMI. First is you effectively get your meter reading cost to zero, right, so we'd save, you know, about 500,000 dollars a year on meter reading cost for the life of the meter, right, so 500,000 dollars over 18 years, what's that, 9 million bucks, right, so it's 100 million dollar cost, 9 million saved. The other benefit that we see in our operations is the remote disconnect, reconnect, right, and there's probably, we have crews in the field that routinely do that work and it's probably about the same amount, 500,000, probably a little less, of

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labour we would be able to reduce because we wouldn't have to send crews or our field service representatives out to customer's premises to disconnect the meter, we could do it remotely from a computer, right. So that's another, you know, over 18 years, so that's another 9 million dollars or so, so we're 20 million dollars into that 100 million dollar investment. Beyond that, there's no significant real cost that we see until we get to that point where we have that true suppertime peak that you can shift and you're really talking about avoided generation. So what we have done is we've—and this really started from that Dunsky report and that report indicated to us that the 2030 to 2034 timeframe is around when AMI would be a net benefit to customers, right, so we took that timeframe and we also know how long it would take to install AMI meters. It's about a five-year project, that's what it was for New Brunswick Power and Nova Scotia Power, their projects were five years to install, and that's roughly what we were for all of our meter change-

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outs, right, so it's a significant effort. So we work back from that timeframe and at that time for us it was indicating, well probably around 2027, 2028, that might be when you start an AMI implementation because you want them in place certainly when you can start getting those benefits, right, as soon as you can, so you're going to need to start early. So what we've done is we worked with a company, Capgemini they're called and they're a consultant that have helped utilities with their AMI business cases, so they understand the technology really well and they have developed for us a tool, you know, that we can routinely update the cost of the technology, if we identify benefits or even new potential benefits, we can layer those in and do that economic analysis. It's not even close to passing right now, so it's not something that we feel we need to do any kind of deep study into, but the point of that, the purpose of that tool is for us to try and model and look forward when we get to that point, you know, because you really need to be kind of

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looking ahead on when we're going to start seeing those benefits and try to pinpoint that as best you can and then work back and say, okay, now here's what I need to install these meters, right. So we've got this took in place now that does that for us, right, that we're working with. Again, at this time AMI meters are not least cost for Newfoundland Power's customers.

FITZGERALD, KC:

Q. But that's the point, that's your conclusion, but that tells me that the study has already been done, but in CA-NP-034, it allows that you're still looking at it, so that analysis, that conclusion it can't be reached it. I mean, you went through it and, you know, there are some assumptions, I guess, that currently it's not providing least cost, but if that's the case, why is it being studied or how can you say that while you're studying it?

MR. CHUBBS:

A. So we've studied it a number of times, right, to see whether it's least cost or not and what came out of the Dunsky study was

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that it could become least cost within the next decade, right, and with a big shift in technology like that and a five-year implementation, so we're talking now it could be five years from implementing, right, so we're continually looking and evaluating. We've got a new study happening right now, our next electrification conservation demand management study being completed by Posterity Group and they'll look at the same thing, right, and they'll take the most recent data in terms of electrification, home heating conversations, EVs, to give us a sense of when we will see and when we would see that new suppertime peak in the future, and that might, you know, might be earlier, might be later, you know, it's really hard to tell at this point, but we've got this tool now that allows us to continually evaluate it as we're going, right. And we're also looking at, you know, the other potential benefits here, they are small, but when I look at Nova Scotia and New Brunswick, you know, they layered on a lot of benefits to kind of

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get to the, to reach that, I think for New Brunswick Power it was 123 million dollar, 120 million dollar investment, but they had a lot of benefits layered in there, right, smaller ones.

FITZGERALD, KC:

Q. You mentioned the potential study, that's the Posterity potential study, but, you know, are smart meters even mentioned in the scope of work for that study? Are they looking at that at all?

MR. CHUBBS:

A. They're looking at conservation and demand management opportunities, the potentials that are there and Time-Of-Use rates is one of those and they evaluate that against the marginal cost on the system, so when they look at any technology and it might, you know, from insulation, you know, they will evaluate the cost of insulation, what are the kilowatt hours, what's the energy you're going to produce, what is the impact on the system demand, right, and they do that economic evaluation and they'll look at Time-Of-Use rates and whether Time-Of-Use

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rates would shift peak enough to reduce that demand impact, right, and that demand impact comes from the cost of adding new generation on the system, right, so the numbers, the inputs that they use in that evaluations are that new generation technology.

FITZGERALD, KC:

Q. No, I understand, but correct me if I'm wrong, the Posterity potential study does not specifically reference smart meters.

MR. CHUBBS:

A. You would need smart meters to implement Time-Of-Use rates.

FITZGERALD, KC:

Q. Yeah, but they don't mention it, it's not part of their study, correct?

MR. CHUBBS:

A. They are not being asked to evaluate the cost benefit of smart meters for Newfoundland Power, they would be asked to evaluate potential conservation demand management alternatives and if Time-Of-Use rates is one of those alternatives that they identify, that would be, we would use that benefit in our analysis for smart meters,

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right.

FITZGERALD, KC:

Q. Right, but you know, not to quibble or be argumentative, but they don't mention smart meters specifically, if you search their report, it's not there, smart meters is not there.

MR. CHUBBS:

A. No, and I think it's important to point out like, you know, Time-Of-Use rates and smart meters are not the same thing, right. You know, smart meters have a bit like a thing like a Venn diagram, I guess. Like smart meters have a lot of benefits and implement Time-Of-Use rates is one of those benefits and there's many ways to go about conservation and demand management and Time-Of-Use rates is one of those benefits, you know, but they don't overlap, you know, it is one part of the potential study, CDM is, and CDM is one benefit of smart meters, right, so they are, they are related but they're not perfectly correlated.

(12:15 p.m.)

FITZGERALD, KC:

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Q. Just to step back a bit, though, in your position as VP in your department and you know that Ontario and BC have mandated smart meters, does that give you pause for thought ever that perhaps Newfoundland Power should adopt smart meters sooner than later?

MR. CHUBBS:

A. No, it does not.

FITZGERALD, KC:

Q. So you're confident then that Newfoundland Power's approach is the correct approach, even though Newfoundland Power has indicated there are many benefits of smart meters to consumers, Newfoundland Power is not prepared at this point to proceed with a serious smart meter initiative imminently?

MR. CHUBBS:

A. Implementing smart meter technology is not least cost for customers of Newfoundland Power at this time.

FITZGERALD, KC:

Q. Okay, and so we've gone through that, that's your conclusion although the jury is not out on that because you're still studying it?

MR. CHUBBS:

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A. We've studied it enough to know smart meters are not least cost for customers at this time and we are continuing to study it to determine if and when they may become least cost for our customers.

FITZGERALD, KC:

Q. So, I think we flogged that to death. Let's move on to other matters. The Provincial Government announced the finalization of its rate mitigation plan recently, as you know. Have you received any direction from the CEO or CFO with respect to the rate mitigation plan?

MR. CHUBBS:

A. No, I have not.

FITZGERALD, KC:

Q. The press release, and I don't know if we have to get there. I think it's part of the record. November 9th, 2023. I believe you're familiar with it, but we can draw it up just in case there's a question about it. November 9th. Okay. This press release states that Newfoundland Power is proposing a 1.5 percent increase in customer rates on July 1, 2024, 2024 rate of return on rate

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base application, a further 5.5 increase on July 1, 2025 in this GRA. Mr. Murray is quoted as saying, "we know that these challenging times for our customers and we understand that reliable service at affordable rates is more important now than ever." Have you received any direction from Mr. Murray with respect to addressing these challenging times for the consumers?

MR. CHUBBS:

A. I would say I get direction from Mr. Murray all the time, when you think of how we manage our business, providing reliable service, ensuring that its least cost for customers, identifying efficiencies in our operations. That's routine conversation with Mr. Murray and I.

FITZGERALD, KC:

Q. But specifically, I mean we talked about the rate shock. We talked about, you know, there's unprecedented increase of, you know, the cost – not the cost, but the expense of electricity to consumers in the current environment and your company's in the business of selling electricity and of

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course, you know, the higher the price goes up, you know, the more difficult it is for both you and the consumer. So, you know, specifically, was there any initiative given to your department to either look at operating costs, look at any kind of savings that could occur in a kind of situation where like this is again a five-alarm fire is going on here or is it there was no reaction to the challenging times statement?

MR. CHUBBS:

A. You know, we understand – I certainly understand it's challenging times for customers and it is engrained in Newfoundland Power's operations that we are constantly looking for ways to reduce costs for our customers. Throughout the evidence, there's many examples of areas where we've been able to achieve cost reductions. We just spoke about meter reading, and that's reduced millions in operating costs for our customers and those are sustained benefits, right, that last throughout this period. LED streetlight technology, that reduced our operating cost 1.8 million dollars a year,

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right, from when we started converting from our high-pressure sodium to our LED streetlights. That's a sustaining benefit, you know, that carries on through this. There's many examples of the smaller incremental operating efficiencies that we've been able to achieve in our operations over the last decade that we have planned and are implementing right now this year in our current year capital budget in terms of our operational technologies that find many little efficiencies in our operations as well, right, and those have sustaining benefits and it is something that Newfoundland Power is constantly focused on and will continue to focus on and I can assure you that we have our customers' interests top of mind at all times.

FITZGERALD, KC:

Q. On another topic, the provisional capital budget application guidelines, which you're familiar with, I believe, were issued by the Board on December 20, 2021 and so that's two and a half years ago, and we understand that Newfoundland Power still does not have an

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asset management program that meets the requirements set out in the provisional guidelines. Is that correct?

MR. CHUBBS:

A. I'm not sure I would necessarily agree. Newfoundland Power's asset management program has provided consistent benefits for our customers, in terms of reliability and in terms of least cost management of the electricity system. The provisional guidelines that were developed a couple years ago, they have some different criteria. They're looking for more granular data, more historical data on things like asset replacement, and it's data that effectively Newfoundland Power doesn't have, you know, and we can't go back in time and get that data, I mean, when you're looking at historical trends and things like that. We've got a few things going on in our operations that have triggered us to do a review of how we do asset management at Newfoundland Power. The biggest and most important one, as I mentioned in my opening statement, is this wave of aging assets that

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we have coming our way. The system was built in the '60s and '70s. Poles, transformers, conductor have lives of 50 to 60 years. You do the math and in the next decade or two, we are going to have a lot of asset replacement to complete at Newfoundland Power. We want to ensure that we do that as cost effectively as we can and, you know, certainly agree that the more data and information that we have at our fingertips to help make those decisions, the better it is for our customers. So, that's number one.

Number two is the provisional guidelines. So, the Board is clearly interested in more data on our assets and how we're making our decisions on how we maintain and replace our assets. And then the third really is our technology. So, the technology that we have in place now for managing our asset management system, so all of our assets was implemented about 20 years ago and is at end of life. The vendor has indicated that it's no longer supported beyond the end of 2026. So, we have to

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replace that technology and that's a very significant piece of technology for us. It's how we manage all of our electricity assets. It has 400,000 assets, you know, and all the data and history and all of our preventative maintenance programs in that piece of software.

So, all of these things are kind of all happening at the same time and so that for Newfoundland Power initiated a review of our asset management program and how we go about asset management to ensure that it's, you know, appropriate, consistent with industry best practice and the like. So, we've – you know, we're into our third phase of this review now and you know, expect that we'll be having conversations with the Board through our capital budget application on what's that going to mean for Newfoundland Power going forward.

FITZGERALD, KC:

Q. Okay. So, I take from your answer then, no. You have not yet met the requirements set out in the Board's provisional capital budget application guidelines. You do have

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a small A asset management program, which you've historically used, but can I ask you then, when do you expect to be in a position to meet the requirements set out in the Board's provisional capital budget application guidelines?

MR. CHUBBS:

A. I think that it's not the right characterization to say we don't meet the guidelines. The Board acknowledged through the guidelines, you know, the fact that they're provisional and also that, you know, encourage the utilities to strive, because they understood utilities did not have all the information that was in there, to strive to meet the spirit and intent of the guidelines and we've certainly done that, and our capital budget application has more data than its ever had, right. The interrogation process, you know, the RFIs and the technical conferences and introduction presentations, the new elements that have been brought to our capital budget application have certainly increased. So, I certainly believe that we are meeting the

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spirit and intent of the provisional guidelines that were put in place.
FITZGERALD, KC:
Q. And so, at some point, you do expect to be in compliance with the provisional capital budget application guidelines?
MR. CHUBBS:
A. Oh, absolutely. We will be working towards that goal. It is not an overnight thing. So, we're doing this review now and it'll inform us on where we need to go in terms of asset management, but that's going to take time, you know. It's looking at assets in a different way. One example is like a health indices, you know, something that we don't – when we inspect a line today, and one of our inspectors goes out and he looks at a pole and he sees that well, that pole is about to fail, it's deteriorated, right, so it's – it fails inspection, for example, and that's captured in our asset management system, right. All the other poles that the inspector is looking at, you know, they get a pass. You know, it's like a pass/fail. That's the kind of way we do our inspections

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now, you know. And again, that's worked for us for a lot of years. But you know, one of the emerging, the newer way to look at it is you assess the health of that pole overall, right. So, you aren't – you're looking at every pole. Well, you're giving it a rating. So, this is a one out of ten in terms of remaining life versus a ten out of ten, you know, for a new line. And that allows you to step back and look at all of your assets once you gather all that data and look at all your assets and get kind of a general sense of the overall health of your distribution or transmission infrastructure and then as your recurring maintenance occurs, is that health generally degrading or improving or staying steady over time, right. And the way we do it today doesn't necessarily give us that information. So, we think like that's likely a part of our inspection program going forward, right, is you're capturing more data on your assets. But it's going to take time to get that data in place and to be able to evaluate the data on a time-based

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perspective, you know.
FITZGERALD, KC:
Q. Sure.
MR. CHUBBS:
A. So, it's going to take time to implement.
FITZGERALD, KC:
Q. Understood, and really that was the purpose of my question, I guess, you know, try to put parameters around the time. Do you have your best estimate as to what time it's going to take?
MR. CHUBBS:
A. I'm not certain that I can say it's a definitive time, you know. There will be things that we change quickly. Our technology is one thing that's got to change quickly because it's approaching end of life. There will be things that'll take a long time to capture the data to be able to make the appropriate decisions on and perhaps it's ten years' worth of data. So, that – so, you know, you got some things we'll do in the next couple years and some things that could take ten years. One of the key elements, and we're

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evaluating our asset management program today against ISO 55000, which is the international standard for asset management, and the real cornerstone of that standard is continuing improvement, you know. It's how are you evaluating what you're doing every year, identifying areas where you can improve and do things better and then how you're tracking and implementing, you know, and so, you know, I really see it as more of I'll say a change in direction and a bit of a longer-term journey. There'll be specific things that we will implement that'll have timeframes and schedules around them, but you know, I almost view it like our health and safety system, you know. That's the way our health and safety system is based on, you know. It's looking at your data every year. What is it telling you, and as a company, what do we need to focus on and try to do better? And that'll be an annual thing at Newfoundland Power, just like it is for health and safety and environment.
FITZGERALD, KC:
Q. So, the short answer is you don't know when

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the asset management – you'll be complying completely with the Board's provisional capital budget application guidelines? You just can't say? You don't know?

(12:30 p.m.)

MR. CHUBBS:

A. The short answer is it is not a definitive endpoint, right. It is not a -

FITZGERALD, KC:

Q. All right. If we could turn now to specific operating costs, and I guess to assist us in this, we'd need to have a look at Exhibit 3, which is Undertaking U-01. So, Mr. Chubbs, what's your role with respect to compiling operating cost data in context of this GRA?

MR. CHUBBS:

A. The operating cost data is taken from a number of inputs within the company. So, it's really a departmental exercise in determining, you know, what costs we've incurred, what we see going forward in terms of any known and measurable changes that are there. It's taking inputs of things like our labour inflation rates, you know, GDP as well. So, it's compiled from a number of

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sources and as that's assembled, it is reviewed by our executive team to determine whether we feel, you know, it's appropriate and we've done all the – we've captured everything that we should be looking at in there. So, that's essentially how it works.

FITZGERALD, KC:

Q. Okay, thanks. If we look at Exhibit 3 that's on the screen there, line 15, operating expenses and here we have operating expenses go from the 73.4 in 2023 to 78 in 2024, which is a significant increase. We've calculated as about a 7.2 percent increase, if you would agree with that or disagree? Would you accept that, that it's a 7.2 increase?

MR. CHUBBS:

A. I'm sorry, which year? I was flipping through my binder.

FITZGERALD, KC:

Q. Okay, sorry. So, the operating expense goes from 73.4 in 2023. I'm looking at line 15.

MR. CHUBBS:

A. Yeah.

FITZGERALD, KC:

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Q. To 78.7 in 2024. So, that's a roughly 5.3 million increase. We calculate that to be 7.2 increase over the time period.

MR. CHUBBS:

A. Yes, that's correct.

FITZGERALD, KC:

Q. Okay. So -

MR. CHUBBS:

A. And I just point out that it may be better if we could work with Exhibit 1 or 2 because I know there are operating expenses that are in our – I'll say my Section 2 evidence and are shown specifically in Exhibit 1 and 2 that I think might be covered in footnote 3 here perhaps, but I know it's in the RFIs as well where – yeah, so, you see footnote 3, right. So, there's adjustments in non-regulated expenses, employee future benefits and things like that that kind of move in and out.

FITZGERALD, KC:

Q. Yeah, but that wouldn't really affect -

MR. CHUBBS:

A. In terms of overall change, you're right, yes. We can agree with that.

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FITZGERALD, KC:

Q. So, let's just stay there for now. So, during this same period or in the June 5th policy statement from the Bank of Canada, the Bank of Canada indicated that the inflation rate was moved down to 2.7 currently. Now, I know that changed yesterday to 2.9 I believe, but would you accept that as the current environment we're in financially?

MR. CHUBBS:

A. Sure, yes.

FITZGERALD, KC:

Q. Sure. So, then the obvious question then is, you know, why is Newfoundland Power's operating expenses forecast to increase by substantially more?

MR. CHUBBS:

A. So, there's a few things in our operating costs that are being affected by external market conditions, also things within the company that are outside of just general inflation. So, we look at all of our costs from an operating perspective. On a labour side, obviously we know where our – we have

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a better idea of where our labour costs are going. From a non-labour perspective, you're looking at GDP, you know, in areas where you see general inflation, but there are areas within the budget where there's specific things. So, you know, an example, 2024 is our conversion to IFRS accounting standard, right. So, there's a single operating expense in there over the period of '24, '25 and '26 – I think I'm wrong, but – I got the year wrong on that one perhaps. But anyway, there's costs in there, like IFRS for a single year or single one-time increases. And then we're seeing cost pressures in technology as well. So, we're seeing incremental cost increases that are beyond GDP driven by external market trends in technology. So, software, licensing fees, things like that, cybersecurity that are driving increases beyond inflation. So, we use inflation where we don't have this kind of idea of where costs are going. But there are costs in here that are beyond inflationary increases.

FITZGERALD, KC:

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Q. Yeah, I accept that, but you know, that's what you've spent the money on or that you've incurred those expenses, but you know, Newfoundland Power is within the overall Canadian economy, if you will, and there are other industries that would say the same thing, that you know, there's been inflationary pressures from different sectors. But still, when you wash it all out, it's – you know, it's 2.7 percent is the inflation rate. But for some reason, Newfoundland Power, who is subject to the same vagaries of the interest markets and all that as every other industry, but they're at seven percent. So, why such a – why is Newfoundland Power such an outlier?

MR. CHUBBS:

A. Well, I mean, first of all, first off, you know, our labour inflation is in here, right. So, our labour inflation is higher than GDP and our labour inflation is based off of negotiated contracts with our unions, collectively bargained contracts. So, they are not tied to general inflation that you're seeing. So, that's a contributing factor that's part of that. And as I said, you know, we have cost pressures that are beyond the level of inflation. So, when we see, for example, if you were to lock it to that GDP level and you see a significant increase, so you have to do, you know, this IFRS conversion which cost a million dollars in that year, you know, you can't go and pull that out of your operations and say, "well, I'm not going to serve my customers now. I'm not going to answer the phones or respond to trouble because I'm incurring this cost over here." You know, they are independent of the general inflation and these are real costs that we're seeing in operating our business.

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FITZGERALD, KC:

Q. You mention the labour costs. When you negotiate with your union and a certain wage level is agreed upon, you know, for the following year or whatever the terms are, does management and, you know, the executive get a similar bump up? Like if the union gets five percent, does everybody get five percent in the organization?

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MR. CHUBBS:

A. No, that's not how it works.

FITZGERALD, KC:

Q. Okay. So, there's no tie in of – so, for example, if there's a manager who's there who's non-union, if there's a union bump up-

MR. CHUBBS:

A. Yeah, thanks. Yeah, thanks for pointing that out because we do have – we do maintain a certain level of separation, you know, from say a trades to a supervisor, you know, and that's there and that's necessary to – you know, you want to maintain that gap. You want those supervisory roles to be filled, you know, preferably from those experienced folks from your union staff. So, you know, it's common practice to kind of keep that separation. So, it can translate to some managerial salaries directly, yes.

FITZGERALD, KC:

Q. Is there any effect on union wage increases on executive bonuses?

MR. CHUBBS:

A. You mean directly like if an increase is up

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four percent, the bonus is up four percent? Is that what you're -
FITZGERALD, KC:
Q. Yeah.
MR. CHUBBS:
A. No, no.
FITZGERALD, KC:
Q. If we go to the application itself, page 1.3, and I'm looking at – scroll down, please. Page 1.3, and if you can scroll up a little bit. Okay, so line 11. "The company reduced its gross operating cost per customer by approximately 9.5 percent on an inflation adjusted basis over the last decade. The effective use of technology has been a primary means through which the company has improved its operating efficiency." So, subject to check, would you agree then over that ten-year period that's referenced there that that implies a 0.9 percent productivity improvement each year?
MR. CHUBBS:
A. Yes, in terms of the reduction, yes.
FITZGERALD, KC:

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Q. Okay. And has Newfoundland Power incorporated the 0.9 percent productivity improvement in its 2024 '25 and '26 forecasts of operating expense?
MR. CHUBBS:
A. So, our – as I mentioned in my opening statement, when we look at what our known labour increase, our forecast labour increases are expected to be from that '22 to '26 timeframe, that's 4.1 percent. So, that's – I'll say that's doing nothing, you know, just through regular labour inflation that we're seeing, you know, in the market and our collectively bargained contracts, we would see a 4.1 percent increase. But through the operating efficiencies that we have in our plan, the increase is 3.1 percent. So, that's a difference of one percent on total operating labour, and that translates into about 1.5 million dollars in reduced operating labour costs over that period.
FITZGERALD, KC:
Q. The period I just spoke about?
MR. CHUBBS:

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A. The period of '22 to '26.
FITZGERALD, KC:
Q. '26, okay. Can we go to page 227 of the application and it's Figure 2-11 and we discussed this with Ms. London, and – I'll wait for you to get there. Okay. So, this is the operating cost per customer 2013 to 2022 and then the figure shows a dip in 2021. Do you have any comment on that? Is there any explanation for that?
MR. CHUBBS:
A. Yeah, so there's a couple of things going on in there. I mean, Covid would be the most significant impact on our operating costs in that time. So, you know, we've all – I guess most of us have experienced the impact of Covid. We didn't – you know, it had large impact on our operations in terms of customers coming into our contact centre, you know, move-in/move-out requirements. University was effectively shutdown here. So, we weren't getting those same standard customer activities. We'd put a pause on disconnect for customers, you know, disconnect for debt through that period of

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time. So, you know, that had a pretty significant impact on our operations, and that's largely what you're seeing there.
FITZGERALD, KC:
Q. Thank you, and so, we look at in – you know, there was a dip in 2021, but it's been hovering since 2015 around $260 per customer. Is Newfoundland Power committed to maintaining or reducing that number to the end of 2026?
MR. CHUBBS:
A. You know, our operating costs per customer up to 2026, you know, is relatively around that level. Again, driven by the effects of – well, obviously the inflationary impacts we spoke about, but also those known – other known increases, right. So, technology costs have been a significant driver for us. All these new software licensing agreements that are coming due, we're seeing market driven increases in technology costs. I mentioned insurance is another area that's been beyond inflation as well and you know, our other company fees. So, costs for consultants, costs for – you know, driven by

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regulation and things that are going on in the sector, right, which is in there as well. So, we're looking at levels that are in that range.

FITZGERALD, KC:

Q. Are you able to – you know, this cuts off in 2022. As an undertaking, can you provide us an updated version of this chart to include 2023, 2024, 2025 and 2026, based on the GRA's forecasts of operating costs and number of customers?

(12:45 p.m.)

MR. CHUBBS:

A. That's actually on the record.

FITZGERALD, KC:

Q. Is it?

MR. CHUBBS:

A. NLH-NP-11, if you want to pull it up.

FITZGERALD, KC:

Q. Save you time. Okay, thank you. If you escalated the operating costs at the Canadian inflation rate and incorporated efficiency improvements, the ones you realized like, you know, the 0.9 percent to offset inflation increases, would you

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significantly reduce your operating costs in the 2026 test year?

MR. CHUBBS:

A. So, you know, these are the costs that Newfoundland Power forecasts are required to meet the needs of our customers in terms of meeting our customer service expectations, providing reliable service to customers, you know, keeping our employees safe and well-trained in there as well. They are based off of the best information Newfoundland Power has available. We have good understanding of where our labour forecasts are going. You know, in areas, in certain areas, you know, you're looking at an inflation adjustment where it's harder to predict where some costs may go. In other areas where we have a good sense of what are our costs are going to look like, like technology as well. So, we've built this forecast with the best available information we have. We've incorporated in here the known efficiencies that we've been able to achieve from – through our operations, largely through the use of operational

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technologies to make us more efficient, and that is built in here as well. So, this is the best forecast available in terms of what is needed to operate the system effectively for our customers at least cost.

FITZGERALD, KC:

Q. Okay. Just bear with me. Thank you, Mr. Chairman. Thank you, Mr. Chubbs. Those are all my questions.

MR. CHUBBS:

A. Thank you.

CHAIRMAN:

Q. Thank you, Mr. Fitzgerald. Mr. Simmons?

SIMMONS, KC:

Q. Yes, thank you, Mr. Chairman. Just – oh, we have a question from the witness?

MR. CHUBBS:

A. I drank a lot of water this morning.

CHAIRMAN:

Q. Five-minute break?

SIMMONS, KC:

Q. The secret is to sip it.

MR. CHUBBS:

A. Sip it, yeah.

CHAIRMAN:

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Q. I was counting the bottles over there.

MR. CHUBBS:

A. Everyone's been counting them.

CHAIRMAN:

Q. We'll take a five-minute break.

MR. CHUBBS:

A. Thank you.

(12:48 p.m. – BREAK)

(12:55 p.m. – RESUME)

CHAIRMAN:

Q. Over to you, Mr. Simmons.

MR. BYRON CHUBBS, CROSS-EXAMINATION BY DANIEL SIMMONS, KC

SIMMONS, KC:

Q. Thank you, Mr. Chairman. Mr. Chubbs, as you probably know, Dan Simmons for Hydro. Mr. Fitzgerald very conveniently left off at NLH-NP-11, which we can go back to please, and to Figure 1, because I've got two or three questions for you about that and that's all I'm going to ask you.

MR. CHUBBS:

A. Okay.

SIMMONS, KC:

Q. Depending on, of course, what your answers

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are. So, forewarned. So, this is – this Figure 1 shows the operating cost for customer from 2013 up to the 2026 forecast and these are inflation adjusted, correct?

MR. CHUBBS:

A. Yes, that's correct.

SIMMONS, KC:

Q. Yes. And if you just go down to footnote number one, it says, "non-labour costs are inflation adjusted during the GDP deflator for Canada. Labour costs are inflation adjusted using Newfoundland Power's labour inflation rates". So, my first question concerns the non-labour costs at the GDP deflator. I understand that that could be used for costs up to the current time. For the forecasts in '24, '25 and '26, do you know how the inflation rate is determined for use in making the inflationary adjustments for this chart? Is it the GDP inflator? Can you do that? Or do you have to estimate future inflation?

MR. CHUBBS:

A. We use the GDP inflator.

SIMMONS, KC:

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Q. Okay. So, that's your source. You follow it that way. Okay, good. Second question, and you may have already answered this. In 2021, there was a dip, and if you look at 2020 and 2022, the per capita cost per – the cost per customer seems to have been the same in 2020 and 2022 and that '21, as the Covid year, would you regard that as an anomaly?

MR. CHUBBS:

A. Yes, when I look at – I had the same question when I saw this graph the first time and I thought what is this standout 2021 dip, and I did have a look at, you know, how it's calculated and we do use GDP when we're doing these inflation adjusted graphs, so we're not -- you know, for non-labour costs anyway.

SIMMONS, KC:

Q. Yeah.

MR. CHUBBS:

A. And you know, the costs in 2020 and 2021, in terms of dollars, were similar but that very high inflation rate that we saw over the period that was above our own forecast, and

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I think it's – I think it's something like seven, six or seven percent, maybe eight percent, that's actually causing that to kind of offset. So, that's one of the, I guess, drawbacks of just using GDP inflators because you don't get that year-over-year kind of movement.

SIMMONS, KC:

Q. So, knowing that was tied to the Covid period and that it didn't continue, would you accept that for the purpose of looking at trends, longer term trends in Newfoundland Power's operating costs per customer, we should probably ignore that dip in 2021?

MR. CHUBBS:

A. Yeah, I think that's reasonable, yes.

SIMMONS, KC:

Q. Okay. And then if you look at the line from let's say 2014 down to 2018, there was a drop.

MR. CHUBBS:

A. Yes, that's correct.

SIMMONS, KC:

Q. And if you then look from 2018 out to say

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the 2023 figure, actual figure, 2023 is actually a bit higher than 2018, isn't it, per capita?

MR. CHUBBS:

A. Yes, that's correct.

SIMMONS, KC:

Q. Right. And then if you look at the forecast from 2023 out to 2026 forecast, it's a bit higher again, isn't it?

MR. CHUBBS:

A. A little bit higher. Yes, that's correct.

SIMMONS, KC:

Q. Right. So, when you look at lines 11 and 12, Newfoundland Power's operating costs per customer from 2013 to 2026 are forecast to reduce by 7.9 percent on an inflation adjusted basis. What actually happened is that all the reductions happened up to 2018. Actually since then, they've increased a bit and they're projected to increase a bit more by 2026, right?

MR. CHUBBS:

A. Yes, we saw significant operating savings in that 2013 to 2017 timeframe, driven largely by our AMI or AMR conversion that we did,

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and that reduced two million dollars that removed two million dollars from our operating costs and another 1.8 with our LED streetlights. So, we're seeing some significant decreases. You know, we're in the period now where we're seeing some above average inflationary pressures on our non-labour costs, right.

(1:00 p.m.)

SIMMONS, KC:

Q. Well, this is inflation adjusted.

MR. CHUBBS:

A. This is inflation adjusted using the GDP deflator, but there are pieces in there that are above inflation, you know, that's driving it. So, we use GDP inflation to – and applied it to all costs when we're looking at it from an historical perspective, but in reality, we are seeing above average inflationary pressures and costs that are beyond GDP, right, and that's one of the – I guess one of the limitations of this graph and this presentation. You're just applying general GDP to all your non-labour costs, right. So, that's part of

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what's going on there.

SIMMONS, KC:

Q. Okay. So, as far as the actual costs per customer goes, not to take away anything from Newfoundland Power's success up to 2018, it's a correct observation though that since then, Newfoundland Power has not had any success in reducing per capita operating costs, for whatever reason, and that looking at the 2026, you're predicting that you're not going to have any success in reducing it in the future, correct?

MR. CHUBBS:

A. We've reduced our operating costs and our labour costs successfully over this period and we forecast further reductions in our labour cost, and that's largely driven by efficiencies that we've been able to find in our operations, and when you look at labour costs separately, those are certainly visible. The non-labour side is where it's a little – it's where we're seeing those above average inflationary pressures. I think what's really important to consider here is when you talk efficiency, you know,

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you're talking about can I do the same amount of work with less money or can I do more work with the same money, you know. And when I look at this graph, and I have the same thought as I'm looking at this, and I think of what we're – what we have going on in our operations today compared to 2016 and 2017. You know, and again take – let's just put aside those large increases we're seeing in these, you know, insurance and technology costs. But you know, we have this aging system that we're dealing with, right. So, we're seeing more equipment failures today than we were five-ten years ago. That's a cost pressure in our operations. You know climate change. We're seeing more storms, more severe weather now, and we see that going forward and it's built into our forecast going forward, as we were in 2016/2017. We've got a younger workforce, right. So, our workforce today--30 percent of our workforce now is under five year's service. We've had a huge transition. Of the 600 or so employees we have, 200 of them we've hired in the last

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five years. So, that's--you know, your less experienced employees, it's driving training cost, right, and it certainly is hard to operate as efficiently without those 30/35 year experienced employees that we've had. You know, from an environment perspective and sustainability, there's an increased focus on sustainability in our operations.

So, you look at our environmental impacts. Our environmental impacts over the last decade were focused on spills and, you know, oil filled equipment, and PCB in oil filled equipment. Now we're measuring things like GHG emissions, you know, and we're talking biodiversity, and when we're putting forward, you know, environmental assessments to the Provincial Government, we're getting more requirements for our projects from an environmental perspective that we have to deal with, right. Those are new or growing costs, or cost pressures that we're seeing.

If you think of cyber security, cyber security is a significant one. You know, five, 10, years ago cyber security was one

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guy in a cubicle at Newfoundland Power, our whole technology group, you know, and that was his role. That is its own department now, right. Cyber security threats are very real. We see it every day, and we have a team of people and they're implementing technologies and solutions to protect, you know, our system and our customer data from, you know, cyber threats, outside threats, and they are constantly, you know, probing our system trying to get in.

You know, we talked about electrification, right, so electric vehicles, home heating conversions. Like those things are different types of low growth on our system that we're not really used to. You know, we're--low growth at Newfoundland Power was new home construction, new subdivision, things like that. Now we're seeing more consumption from customers. And, you know, we have folks who are spending time and effort trying to understand how are we going to deal with this type of growth in the future,

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right. So, that's another cost pressure.

And if I could add one more, like regulation. Regulation is a cost pressure at Newfoundland Power. Our capital budget intervention in the last few years has been higher than it's been historically, and that comes at a cost, right, for Newfoundland Power. So, those are all cost pressures that we see, and it's really new work requirements.

So, when I look at this graph, I see Newfoundland Power doing a lot more with the same resources that we had 10 years ago, you know.

SIMMONS, KC:

Q. That was going to be my last question, and I wasn't expecting as long an answer as you just gave, and I take your answer to be that, yes, costs are forecast to increase in 2026 over the 2023 actual year, which I think is what I--I think is what I've asked, and you've explained that rate payers are going to get more for their dollar so it's worthwhile. Is that the gist of what you're

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saying? All these benefits you're talking about that they're going to receive make it worthwhile and Newfoundland Power therefore deserves to get paid more per capita for their operating expenses in order to deliver those benefits to the rate payers?

MR. CHUBBS:

A. I view the service that our customers receive as providing good value to our customers, and we survey our customers routinely. We've had consistent customer satisfaction levels over the last decade. That tells us that we're focused in the right areas, and the cost that we have put forward here, including the cost pressures that I've spoken about, are reasonable costs, and they're necessary costs, that we need to manage the system in a reliable manner, in an environmental responsible manner, and least cost manner for our customers.

SIMMONS, KC:

Q. And this is the last question. I had referred you before to lines 11 and 12, and

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I think we've just established that operating costs per customer have not reduced since 2018, and are not projected to reduce since 2018. So, when in those lines you choose to say that from 2013 to 2026 operating costs are forecast to reduce, when in fact they're not forecasted to reduce at all since 2018, would you agree with me that that could be a misleading statement?

MR. CHUBBS:

A. No, not at all. The question that Hydro posed to Newfoundland Power in this RFI asked us to provide an updated figure of 2.11, and Figure 2.11 in our evidence is the operating cost per customer from 2013 to 2022, I believe, and it had demonstrated there that our operating cost reduced by 9.5 percent over that period, and we were asked to provide the updated graph extended out to 2026, which is what we did, and we provided the updated operating cost per customer number that was a part of the original presentation. So, it seems to me like we've provided what was asked in the information

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request.
SIMMONS, KC:
Q. Thank you very much. No further question, Mr. Chairman.
CHAIR:
Q. Thank you, Mr. Simmons. Over to Ms. Greene. Sorry, IBEW.
MS. DING:
Q. No questions, Mr. Chairman.
CHAIR:
Q. Sorry about that. Thanks. Over to Ms. Greene.
MR. BYRON CHUBBS, CROSS-EXAMINATION BY MAUREEN GREENE, KC
GREENE, KC:
Q. Thank you, Mr. Chair. Good afternoon, Mr. Chubbs. I have a few general areas of questions that I wanted to review with you before we discuss operating costs, and I doubt we will finish the questions today. The first area I wanted to talk to you about is reliability, and you've already had some discussion with Mr. Fitzgerald this morning about that, and I am following up on some of

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that discussion.
First, could you explain how Newfoundland Power evaluates their performance for reliability? How do you do that?
MR. CHUBBS:
A. I look at reliability performance at Newfoundland Power using a lot of metrics, you know, and maybe I'll take an engineer's perspective. I look at it in terms of inputs and outputs into the system.
So, first off, and I got into a bit of this this morning, on the input side, like what is Newfoundland Power doing to manage reliability, and that's those three areas that I spoke about in terms of building our system to the appropriate standards, and in maintaining our system, consistent with utility best practice, and then obviously responding effective to customer outages when they do occur. So, those are the three key inputs in my view in terms of how you manage reliability and how you evaluate it.
Then on the output side you're looking

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at your lagging data, what is the system telling you. So, we look at metrics like our SAIDI, our average duration of outages. We look at metrics like SAIFI, the frequency of outages, and I explained that, you know, this morning in terms of what that means. We compare that.
When we evaluate those liability indices, we compare that to where we were historically as a company, you know, and we see that we've been fairly stable over the last decade, which is where we feel we're good. We evaluate it against peers. So, we evaluate our reliability against, you know, the CEA, Electricity Canada, Region 2 numbers, and that kind of gives us some perspective of where we are in terms of overall reliability. So, that's the reliability numbers.
Then there's customer satisfaction, you know. So, we survey our customers every quarter. We consistently get customer satisfaction levels that are, you know, that 86 to 88 percent range, and we've been very

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consistent over the last decade in achieving that. And when we ask our customers why you gave us this rating, the two things that are always--the top are cost and reliability. Those are the two, top two, all the time. So, that tells me that we're doing a good job of managing reliability.
Then we look at cost. You know, that would be another, right. And, you know, we see our operational performance here, and operating cost per customer data. You can look at that a number of ways. There's some good data.
GREENE, KC:
Q. Can we leave operating cost per customer for now? We'll come back to that.
MR. CHUBBS:
A. Sure.
GREENE, KC:
Q. But you do look at that as one way of evaluating your performance.
MR. CHUBBS:
A. And another is--like there's a good RFI where we provide data on total T and D

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investment in Atlantic Canada, right.
GREENE, KC:
Q. And we're going to come to that as well.
MR. CHUBBS:
A. Right. So, that's another area. So, when I look at those and I compare how we're doing historically, and how we're doing compared to peers, that tells me we're doing a good job of managing reliability. So, on the inputs and outputs side I think Newfoundland Power is doing a good job overall in managing reliability to our customers.
GREENE, KC:
Q. You mentioned that you look at the lagging indicators as one measure. What are the metrics that you use there? Is it only SAIDI and SAIFI?
MR. CHUBBS:
A. You know, for distribution, primarily a distribution utility, which is--Newfoundland Power, you know, a large part of our operations is distribution. The single most common metric for reliability is SAIDI, right. We talk about SAIDI a lot, or SAIFI

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a lot here too as well, but really SAIFI is a part of SAIDI. You know, it's that two outages a year that our customers see, and then when you add in our average response time of 1.3, or multiple it in there, you get that 2.6 overall number. So, SAIDI is the key metric for Newfoundland Power. And then you can--like I said, you can break that out and look, okay, how are we doing on frequency of outages, and how are we doing on our operational response.

So, you can kind of--you can dive deeper, and you can also dive deeper in terms of major events, you know. So, we factor our major events, and events that are kind of beyond the design of your system, but, you know, you can look at that data and you can get information from that data as well in terms of how you're responding to--how resilient is your system, right? How do you bounce back from these major storms and things? So, we look at that data. And I mentioned customer satisfaction is another--and I also mentioned cost. So, those are

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the three.
GREENE, KC:
Q. And when you look at the SAIDI and SAIFI metrics, those are the metrics that are used by other Canadian electrical utilities to compare performance, is that correct?
(1:15 p.m.)
MR. CHUBBS:
A. Yes, that's correct. Pretty much every distribution utility that I'm aware of uses SAIDI and SAIFI as key metrics.
GREENE, KC:
Q. And that data is readily available for comparison purposes, is that correct?
MR. CHUBBS:
A. The data, it's on the record where Newfoundland Power is compared to Electricity Canada Region 2 average. The data is not available separately. You know, the data is reported, and the agreement with Electricity Canada is that it can only be used by other utilities in an aggregate manner. So, that's how we go about -
GREENE, KC:

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Q. I think it would be helpful if we brought up to see the Figure 2.5 in the application on page 2-17. And these are the measures you report routinely to the Board to allow the Board to also evaluate how Newfoundland Power is performing from a reliability perspective, is that correct?
MR. CHUBBS:
A. This Board you mean?
GREENE, KC:
Q. Yes.
MR. CHUBBS:
A. Yes.
GREENE, KC:
Q. So, here we see SAIFI under normal operating conditions, and normal operating conditions means excluding unusual events and loss of supply from Hydro, is that correct?
MR. CHUBBS:
A. Yes, that's correct.
GREENE, KC:
Q. So, SAIFI is also--for the frequency of outages, that is also where you are broadly consistent with the Canadian average, is

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that correct?
MR. CHUBBS:
A. Yes, that's correct.
GREENE, KC:
Q. And that's what we see if we look there. Actually, if we go to Figure 2.7, and her we can see--because it's always a picture says a thousand words sometimes, that it is broadly consistent with the Canadian average. Is that what we should take from Figure 2.7?
MR. CHUBBS:
A. Yes, that's correct.
GREENE, KC:
Q. Now, the other measure that's used by all utilities for reporting on their performance is SAIDI. So, here if we could go, please, to Figure 2.6. Again, we see SAIDI under normal operating conditions, and we see that there was an improvement from 2014 down to--a little blip in 2018, and then 2020. So, in 2013/2014, are we seeing there some of the impacts of what is anecdotally referred to as DarkNL?

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MR. CHUBBS:
A. No. So, DarkNL would be considered a major event for Newfoundland Power, so it is excluded from this data. I think there is a graph in the evidence that shows, if you want to pull it up, but it does exclude Dark NL.
GREENE, KC:
Q. The next one is how we compare to the Canadian average, which is Figure 2.8. And this is where we see that Newfoundland Power is performing 40 percent better than the Canadian Electricity Canada Region 2. Perhaps you could explain what Region 2 utilities are.
MR. CHUBBS:
A. Yes, I can. I think the utilities are actually included if you go back to page--footnote 35 on page 2-19. That actually lists the utilities that identify as Region 2. And Region 2 utilities are utilities that have a mix of urban and rural customers, right. So, you know, a utility like Toronto Hydro, for example, wouldn't be

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a Region 2 utility because it's all urban, a lot of underground infrastructure, and their crews are generally closer to where trouble occurs. And you'd see some very rural utilities that wouldn't be included here either because they're for--you know, the response time is so much longer. So, Electricity Canada provides these different regions of utilities. So, it's not geographical region, it's based on the customer mix.
GREENE, KC:
Q. And these are the utilities that you would consider to be your peers for evaluating reliability performance, is that correct?
MR. CHUBBS:
A. These utilities would be the most comparable to Newfoundland Power in terms of their customer mix, yes.
GREENE, KC:
Q. Is there any other readily available source of data that would allow a comparison of your performance versus other utilities? For example, we see that there are--you can

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see that Newfoundland Power's performance versus other Canadian utilities from a reliability perspective because that data is available for what was the old Canadian Electricity Association, but there's no similar data available for operating cost per customer, is there, for Canada?
MR. CHUBBS:
A. No, that's correct. There's--we haven't been able to source a comparable peer group for Canada because it's not something that's recorded and reported on. That's why we use the US comparison peer group for our operating cost per customer.
GREENE, KC:
Q. I would like now to go to the RFI you referred to, which is PUB-NP-046, which is where we see another comparison of the cost of Newfoundland Power per transmission and distribution, but it is capital, not operating, but we see a comparison of Newfoundland Power's cost on the capital side compared to other Atlantic Canadian utilities. So, this goes to the question of

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the cost being paid for reliability which was discussed with you earlier today, and whether there's additional cost being incurred. If we look at Table 1, we do see that the capital investment cost for the period again 2013 to 2022 has been lower than the other Canadian Atlantic utilities, and also the capital investment per customer. I wanted you to explain how we should interpret that data and what should we take from this table?

MR. CHUBBS:

A. I think what can be taken from this table and, you know, it's worth pointing out that it is really difficult to compare utility to utility. Every utility is different in terms of storms, in terms of, you know, geography, you know, just historical growth of the system, you know, when things became electrified and rebuilt, and all that. So, it's always a challenge to go utility to utility, but what this table tells me is that our level of investment in our electricity system is reasonable when we

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compare that to the rest of Atlantic Canada.

GREENE, KC:

Q. And when you looked at, or discussed earlier, that how you look at the balance of the cost, one is the design standard that must be maintained. So, that design standard in what Newfoundland Power builds would be captured in these numbers, is that correct?

MR. CHUBBS:

A. Yes, that's correct. We've been building to the current design standards. So, the shift in electricity, or the Canadian Standards Association, to severe weather loading for Newfoundland and Labrador occurred in early 2000's. So, throughout this period here you would see all this investment that occurred over that period, from 2013 to '22, would be built to the current--current standard.

GREENE, KC:

Q. And we've already established that there's no comparable data available to compare your operating cost per customer to others, is that correct, and Canada.

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MR. CHUBBS:

A. In Canada, that's correct. For Canada we do have a US peer group that we use.

GREENE, KC:

Q. I had intended to ask you how did balance cost from capital and operating perspectives with respect to reliability and what's required. Now, Mr. Fitzgerald did take you through that, and I was just going to give you the opportunity if there's anything else you wanted to add without repeating some of the answers to the questions. How does Newfoundland Power balance the issue of the cost to customers versus the reliability that is required to supply customers adequately?

MR. CHUBBS:

A. I think the key message there is that in Newfoundland Power's view, and from our operational experience, that a reliable system is an efficient system. And if you're managing your system in a manner that gets the maximum life out of your assets, and you're inspecting it in a way that you

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are replacing assets prior to failure as best you can, we can't always do that, that that is the least cost way to maintaining your electricity grid that provides good reliability outcomes for customers and does so at the lowest possible cost.

GREENE, KC:

Q. You also earlier talked about a review that had been done by Liberty in response to DarkNL, which reviewed one of the other factors that you say are important, which is the maintenance of the system. Have there been other reviews done as well, and if so, when? Do you recall?

MR. CHUBBS:

A. We haven't done any reviews on the maintenance of the system since the Liberty review, other than the fact that we are now going through a review of our approach to asset management for reasons that I mentioned earlier, right.

GREENE, KC:

Q. Prior to Liberty, were there reviews undertaken at the direction of the Board

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with respect to Newfoundland Power's performance from a reliability and cost perspective, an operational review?

MR. CHUBBS:

A. The last review that I was aware of prior to Liberty, and this is before my time at Newfoundland Power, so I may get some details wrong, but effectively Newfoundland Power's reliability performance was not great in the mid to late '90's, and because of that, the Utilities Board saw fit to complete a review of Newfoundland Power's liability performance, and the result of that review was a recommendation that Newfoundland Power should seek to improve the overall reliability that we provide to our customers. And following that review, that was when, as I mentioned earlier, in the early 2000's where we changed our approach to asset management. That's when we implemented our current asset management technology, where we developed our asset management strategies for our generation substation transmission and distribution

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systems, incorporated more preventative maintenance. So, we were doing more work on a plan fashion driven by inspections and not responding to trouble. And in the 10 or so years following, so from that year say 2000 to 2010, we saw an overall improvement to reliability that our customers received, while at the same time our operating cost per customer actually came down, right. So, that is what supports our view that a reliable system is an efficient system.

GREENE, KC:

Q. So, there have been two operational reviews of hydro that were directed by the Board, one was around 2000, or a little bit earlier, and another in 2014. Do you think those types of periodic operational reviews are helpful to be able to explain to customers and also for Newfoundland Power to look at how they're balancing cost and reliability?

MR. CHUBBS:

A. I would consider the outcomes that customers are receiving as a key indicator of whether

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a review of reliability was necessary. You mentioned, or I mentioned, Newfoundland Power in the late '90's. You mentioned Newfoundland and Labrador Hydro in 2014 following DarkNL. So, both of those situations were times when it didn't appear the level of reliability customers were experiencing was appropriate. And at that time, in those times, it made sense to complete a review. When I look at Newfoundland Power right now, our reliability that we've provided to our customers over the last decade has been very consistent, and our customer satisfaction levels when we survey our customers has been very consistent over that decade. So, that tells me that we're getting it right.

GREENE, KC:

Q. Mr. Chair, it's 1:30.

CHAIR:

Q. Okay. We'll adjourn for the day. Thank you.

MS. GLYNN:

Q. Mr. Chair, before we go, just to, I guess,

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plan for tomorrow, we will finish with Mr. Chubbs and we will start with Mr. Comerford. If anybody has any comments on that I guess we can address that now as opposed to –

MR. O'BRIEN:

Q. I'm just wondering how long we might be with--I guess my question is more along the lines of are we going to get to Mr. Bowman rather than sort of--or are we going to wait until Friday, and if that's fine, I'm okay with that, but I'm just asking the question.

GREENE, KC:

Q. I will be a significant period with Mr. Chubbs -

MR. O'BRIEN:

Q. Okay. Well, it would make sense that -

GREENE, KC:

Q. - but it won't be past the break.

MR. O'BRIEN:

Q. No, no, but it would make sense then that we're not going to get to Mr. Bowman.

MS. GLYNN:

Q. I think Mr.--finish Mr. Chubbs and Mr. Comerford might be our –

MR. O'BRIEN:
Q. And that's all I was wondering.
MS. GLYNN:
Q. Our only plan for tomorrow.
MR. O'BRIEN:
Q. Okay.
CHAIR:
Q. It is difficult to predict. We can ask the questions but we have no idea how long the answer is going to take.
MR. O'BRIEN:
Q. That's a dig at you, Mr. Chubbs.
CHAIR:
Q. That's what's relevant.
MR. O'BRIEN:
Q. And, Mr. Browne, you had your own witness like that.
BROWNE, KC:
Q. If the shoe fits.
MS. GLYNN:
Q. The long and the short is the probability of getting to Mr. Bowman is very low tomorrow.
CHAIR:
Q. Thank you, everyone.

Upon conclusion at 1:31 p.m.

CERTIFICATE

I, Judy Moss, hereby certify that the foregoing is a true and correct transcript of hearing in the matter of Newfoundland Power Inc. 2025-2026 General Rate Application heard on June 26th, 2024 before the Newfoundland and Labrador Board of Commissioners of Public Utilities, 120 Torbay Road, St. John's, Newfoundland and Labrador 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 26th day of June, 2024

Judy Moss

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