M12451

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF: ***THE PUBLIC UTILITIES ACT***

\- and -

IN THE MATTER OF: **OF A GENERAL RATE APPLICATION BY NOVA SCOTIA POWER INCORPORATED** for approval of certain revisions to its Rates, Charges, and Regulations

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TRANSCRIPT

HEARD BEFORE: Mr. Stephen T. McGrath, K.C. Chair
Mr. Roland A. Deveau, K.C., Vice Chair
Mr. Steven M. Murphy, MBA, P.Eng., Member

PLACE HEARD: Offices of the Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, Nova Scotia

DATE HEARD: Wednesday, January 7, 2026

APPEARANCES:

APPLICANT: **Nova Scotia Power Inc. (NSP)**
Mr. Colin J. Clarke, K.C.
Ms. Jennifer Power, Counsel
Mr. Geoffrey Breen, Counsel
Mr. Blake Williams, Senior Director, Regulatory Affairs

INTERVENORS:

Consumer Advocate
Mr. David J. Roberts, Counsel
Mr. Michael Murphy, Counsel

Small Business Advocate
Ms. Melissa P. MacAdam, Counsel
Ms. Rebekah L. Powell, Counsel

Affordable Energy Coalition
Mr. Peter Duke
Mr. Chris Benjamin

Eastward Energy Incorporated
Ms. Allison Coffin, MBA, P.Eng.
Ms. Angela Costello, Regulatory Analyst

EffiencyOne
Mr. James Gogan
Ms. Lucia Westin-Eastaugh

Industrial Group
Ms. Nancy G. Rubin, K.C., Counsel
Ms. Brianne Rudderham, Counsel

Municipal Electric Utilities of Nova Scotia (MEUNS)
Mr. James MacDuff, Counsel

Natural Forces
Mr. Austen Hughes
Ms. Meg Morris

Nova Scotia Department of Energy
Mr. Daniel Boyle, Counsel
Mr. Girish Patel

Nova Scotia Independent Energy System Operator (NSIESO)
Mr. Jason T. Cooke, K.C.
Ms. Danielle J. Keating, Counsel

Nova Scotia Liberal Caucus
Mr. Chris Abraham
Mr. Iain Rankin

Nova Scotia NDP Caucus
Ms. Claudia Chender
Ms. Susan Leblanc

Port Hawkesbury Paper LP
Mr. David MacDougall, Counsel
Mr. James MacDuff, Counsel
Ms. Melanie Gillis, Counsel

Renewall Energy Inc.
Mr. Daniel Roscoe, P.Eng.

SWEB Development
Mr. Mason Baker, P.Eng.

BOARD COUNSEL: Mr. William L. Mahody, K.C.

BOARD STAFF:
Mr. Steve Pronko, Director, Electrical Advisory Services
Ms. Libby McNamara, Director, Risk and Financial Advisory Services
Ms. Holly Chisholm, Advisor (Economics/Finance)
Mr. Robert Norwood, Public Proceeding Assistant
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LIST OF EXHIBITS

<u>**LIST OF UNDERTAKINGS**</u>

LIST OF UNDERTAKINGS

Halifax, Nova Scotia

--- Upon commencing on Wednesday, January 7 at 9:00 a.m.

THE CHAIR: Good morning, everyone.

This is a hearing of the Nova Scotia Energy Board for an Application by Nova Scotia Power Incorporated to approve certain revisions to its Rates, Charges and Regulations.

My name is Stephen McGrath; my pronouns are he/him, and I'm the Chair of the Board.

The Board encourages the sharing of pronouns and titles by those who choose to do so.

I am joined on the Panel hearing this matter by Vice Chair Roland Deveau on my left and Board Member Steven Murphy on my right.

Board staff assisting with the hearing, seated in front of me, are Jeff Goodine, Robert Norwood and Svitlana Lykhina. We're also joined by Dale Waterman from International Reporting.

Notice of Hearing for this proceeding

was published in the *Chronicle Herald* on September 30th, October 23rd, and October 25th. Notice was also published in the *Cape Breton* Post on October 23rd and October 25th and proof of advertising was filed with the Board and marked as Exhibit N-19.

This proceeding is also being recorded, as is the usual practice of the Board, and it is also being livestreamed. Witnesses in this matter will be appearing in person and virtually.

To accommodate the streaming of the hearing, cameras have been set up at the front of the hearing room and parties who are giving Opening Statements or who ask questions of witness panel are asked to come up to the tables set up at the front of the room when it is time to do that so that anyone watching remotely can see.

I'll go down the list of parties in a moment to ask representatives to identify themselves for the formal record of the hearing, but that can be done from the microphones at your tables. There's no need to come up to the front for appearances.

Some information in this proceeding has been filed confidentially. If it is necessary to go into a confidential session with any of the witnesses, the public streaming of the hearing will be discontinued for the duration of the confidential session, and the hearing room will be cleared of anyone who’s not been approved for access to confidential information in the proceeding.

For hearing participants who are connecting virtually, a separate link has been sent for the confidential virtual sessions, and it will be necessary for those people to sign off the public broadcast and connect to the confidential session.

The Board received a number of letters of comment relating to this matter which have been compiled into one exhibit and marked N-1. The Board did not receive any requests from the public to speak at the hearing, so the evening session that was scheduled for tomorrow has been cancelled.

We will try to have 15-minute breaks midmorning and midafternoon and break for an hour for lunch sometime around 12:30. We'll target breaking for the day some time between 4:30 and 5 o'clock, although these times may vary or be extended depending upon the flow of evidence in the proceeding.

You may have noticed that the washrooms on this floor are currently under renovation. They're being converted to gender-neutral facilities. My understanding is that they are functional at this time. There's actually no sinks. There is a handwashing station. But if you prefer, there are fully functional washrooms available on other floors in the building.

If there's a fire alarm, there are staircases off the halls on either side of the elevators, and everyone is asked to take the stairs to the ground level and exit the building at the back on the harbour side and gather at "The Wave" on the boardwalk to the left of the door as you exit.

I'll now go on to appearances. I'm going to go down the list of parties and ask for introductions, beginning with Nova Scotia Power.

MR. CLARKE: Good morning, Mr. Chair, Board Members. Colin Clarke, Jennifer Power, Geoff Breen for Nova Scotia Power. I'd also add that Peter Gregg, President and CEO of Nova Scotia Power, is with us this morning.

THE CHAIR: Thank you.

Consumer Advocate...?

MR. ROBERTS: Good morning, Mr. Chair. David Roberts and Michael Murphy for the Consumer Advocate.

THE CHAIR: Small Business Advocate...?

MS. MacADAM: Good morning. Melissa MacAdam and Rekebah Powell for the Small Business Advocate.

THE CHAIR: The Affordable Energy

Coalition...?

MR. DUKE: Good morning, Mr. Chair. Peter Duke and Chris Benjamin for the Affordable Energy Coalition.

THE CHAIR: Eastward Energy? I'm not sure if they were planning on being in the room physically. I don't see them.

EfficiencyOne, the same thing.

Industrial Group...?

MS. RUDDERHAM: Good morning, Mr. Chair. Brianne Rudderham for the Industrial Group. My colleague, Nancy Rubin, will be joining us shortly. She has a motion that couldn't get rescheduled.

THE CHAIR: Thank you.

Municipal Electric Utilities of Nova Scotia...?

MR. MacDUFF: Good morning, Mr. Chair, Board Members. James MacDuff on behalf of Municipal Electric Utilities.

THE CHAIR: Good morning.

Nova Scotia -- sorry. Natural Forces? Anyone here for Natural Forces?

Nova Scotia Department of Energy...?

MR. BOYLE: Good morning, Mr. Chair. Daniel Boyle appearing for Department of Energy.

THE CHAIR: Nova Scotia Independent Energy System Operator, anyone attending in person for them this morning?

Okay, I don't see them.

Nova Scotia Liberal Caucus...?

MR. RANKIN: Good morning. Iain Rankin, MLA for Timberlea-Prospect, here on behalf of Nova Scotia Liberal Caucus.

THE CHAIR: Good morning.

The Nova Scotia New Democratic Party Caucus...?

MS. CHENDER: Good morning, Mr. Chair. Claudia Chender, Leader of the Official Opposition, here on behalf of the New Democratic Party.

THE CHAIR: Good morning.

Port Hawkesbury Paper...?

MR. MacDOUGALL: Good morning, Mr. Chair. David MacDougall and Melanie Gillis appearing on behalf of Port Hawkesbury Paper.

THE CHAIR: Renewall Energy...?

MR. ROSCOE: Good morning. Daniel Roscoe here on behalf of Renewall Energy Inc.

THE CHAIR: SWEB Development? I'm not seeing them in person either. Okay.

Board counsel...?

MR. MAHODY: Good morning, Mr. Chair, Board Members. Bill Mahody, Board counsel, joined at counsel table by Steve Pronko, Libby McNamara, and Holly Chisholm, Board staff.

THE CHAIR: Thank you.

Before moving on to Opening Statements, are there any preliminary matters that any of the parties wish to raise at this time?

Mr. Mahody.

MR. MAHODY: Thank you, Mr. Chair.

Mr. Chair, this morning I've provided to Mr. Goodine CVs for the Doane Grant Thornton witnesses, Ms. Brown and Mr. Griffiths. I would ask that those two CVs be marked as an exhibit, please.

THE CHAIR: Just one exhibit or two, Mr. Mahody; does it matter?

MR. MAHODY: It doesn't to me, Mr. Chair.

THE CHAIR: Okay. So we'll mark them together as one exhibit. It's the CVs for the Grant Thornton witnesses. And that will be marked as Exhibit N-42.

--- EXHIBIT NO. N-42:

CVs of Barry Griffiths and Angie Brown, Doane Grant Thornton

MR. MAHODY: Thank you, Mr. Chair.

THE CHAIR: We'll now move on to Opening Statements, beginning -- these have all been pre-filed and marked for identification in our exhibit list, beginning first with Nova Scotia Power, which has been marked as N-40.

MR. CLARKE: Mr. Chair, obviously it's the wish of the Panel. In the past, Nova Scotia Power has been offered the opportunity to give the last Opening Statement. We'd ask for that opportunity today, but, again, it's the wish of the Board.

THE CHAIR: That's fine, Mr. Clarke.

So we'll move on first, then, to the Affordable Energy Coalition, Mr. Duke.

MR. DUKE: Thank you, Mr. Chair. Should I come to the front first?

THE CHAIR: If you wouldn't mind, that would be appreciated.

OPENING STATEMENT BY AFFORDABLE ENERGY COALITION

MR. DUKE: Good morning, Mr. Chair, Board Members. My name is Peter Duke. My pronouns are he/him. I'm here on behalf of the Affordable Energy Coalition, who works on behalf of low and modest income Nova Scotians across the province.

Nova Scotia has one of the highest rates of energy poverty in the country due to lower incomes, high energy cost, and older housing stock.

In 2023, Efficiency Nova Scotia estimated that 43 percent of households spend more than 6 percent of their net income on energy, a widely accepted threshold of energy poverty. Energy poverty undermines household stability for safety, forcing families to make untenable choices between food, medicine, adequate heating or cooling.

Energy services are not optional. They are necessities for health, safety, and dignity, and access is increasingly threatened by low income and volatile energy prices.

Affordable Energy has four concerns with Nova Scotia's General Rate Application.

One, affordability, immediate support for low-income households. Low- and modest-income households are disproportionally affected by rate increases. They face disconnections more often and are the least able to absorb higher costs.

[9:10:03] Other jurisdictions have acted. Ontario's Electricity Support Program provides on-bill credits to low-income customers. In Nova Scotia, a multi-stakeholder energy poverty taskforce made up of government, Nova Scotia Power, and community organizations, and supported by poverty -- energy poverty expert, Roger Colton, developed a made-in-Nova Scotia Home Energy Affordability Program. That program includes on-bill credits, arrears management, crisis support, and enhanced energy efficiency and electrification measures. Despite being presented to government in 2024, no action has been taken. We submit that the Board could review this work and consider whether to recommend similar universal service program, particularly as other supports, such as HARP and Federal Oil to Heat Pump funding have been reduced or exhausted.

Two, affordability. Excessive profits during a cost-of-living crisis. Public regulation of a monopoly is meant to ensure cost recovery while preventing excessive profits. The allowed return on equity is central to this balance. Low-income Nova Scotians are experiencing intolerable cost of living pressures. Rate increases add to this burden. We therefore welcome the evidence of Dr. Sean Cleary, CFA, who concludes that Nova Scotia Power’s requested ROE is too high and recommends 7.6, well below -- percent, well below the company’s request.

While many households struggle to keep the lights on, Emera’s financial health remains strong. Reducing the ROE would save millions for tax -- for ratepayers, while ensuring access to capital. In our view, the suggestion is both reasonable and necessary.

Three, energy transition. A chance to lower bills and eliminate energy poverty. Nova Scotia is in the midst of a historic transition to a zero-carbon energy system. The Affordable Energy Coalition supports this transition, which is essential for climate stability and offers a powerful opportunity to reduce energy costs. Investments in insulation, efficient heating such as heat pumps and solar power, reduce total energy demand and can lower bills even as rates increase. However, these benefits are only realized if energy efficiency programs are adequately funded and accessible to low-income households.

Nova Scotia has been a leader in efficiency, but recent rankings show we are falling behind other provinces. We urge the Board to ensure that efficiency investments, especially for low-income households, increase, rather than decrease, as rates rise.

Technological neutrality. Lowest cost means full cost. Decisions about new generation should be based on clearly defined needs, not preferred fuel types. Natural gas is only one option among many, including battery storage and demand flexibility. By example, our neighbours in New Brunswick just announced they are seeking proposals for battery energy storage systems to minimize risk and provide the lowest long-term price to their customers.

We are concerned that full systems cost, including fuel volatility, stranded assets, and carbon pricing, are not always adequately accounted for. Evidence from other jurisdictions show that renewable systems can meet reliability needs at comparable or lower total cost while insulating customers from price volatility. Affordability must be at the centre of this proceeding. Those most affected by rate increases, low-income households, rarely have the opportunity to be heard, yet bear the greatest burden. As Nova Scotia transitions to a cleaner energy system, we must ensure that no one is left behind. With the right affordability protections, efficiency investments, and regulatory decisions, we can reduce energy poverty while building a sustainable energy future.

Thank you, Mr. Chair and Board Members.

THE CHAIR: Thank you, Mr. Duke.

I'll next call on the Nova Scotia Liberal Caucus.

<u>OPENING STATEMENT BY NOVA SCOTIA LIBERAL CAUCUS</u>

<u>MR. RANKIN:</u> Good morning, everyone.

Members of the Board, Mr. Chair, thank you for the opportunity to appear before you today to speak about Nova Scotia Power's General Rate Application.

I am appearing today on behalf of Nova Scotians who cannot afford to continue paying more year after year for electricity that is too often unreliable. And let me be clear at the outset; the Nova Scotia Liberal caucus opposes Nova Scotia Power's request for an 8 percent increase over two years. Nova Scotians are already paying too much for power, and the pattern of repeated unpredictable increases has become unsustainable for families, for small businesses, and for our economy.

Electricity is an essential service. When the cost of that service rises faster than incomes and inflation, the consequences are real and immediate. I hear everyday from Nova Scotians struggling with the cost of power, and if you ask any MLA, we all know constituents who have missed rent payments or families who have had to choose between heat and groceries, or businesses delaying investment and raising prices to try to keep up with their increased cost.

For many Nova Scotians, one higher power bill is all it takes to push them over the edge of their financial limits, and that reality is why our caucus has intervened this morning.

This General Rate Application does not exist in isolation. It is part of a broader and troubling pattern. Over the last four years, Nova Scotia Power has repeatedly returned to regulators seeking various forms of rate increases and additional charges. In January 2022, the utility applied for a rate increase and the Board approved a rate hike of roughly 14 percent and translating into average increases of 6.9 percent in 2023 and 2024. Thankfully, this hike was ultimately limited by a $500 million federal loan to bail the utility out of a precarious financial situation and prevent the rate shock.

In April 2024, the Board approved an additional increase through the Fuel Adjustment Mechanism. Just eight months later, in December 2024, the Board approved a storm cost recovery rider, raising rates again. And now Nova Scotia Power is before you once again seeking further increases through this General Rate Application, a proposal that would force families to pay hundreds of dollars more each year for electricity by increasing standard residential rates by 3.9 percent and 4.1.

For a family, this could mean spending $400 more each year on electricity. And that’s a troubling figure for families who are trying to make ends meet.

Taken together, these Applications demonstrate a troubling pattern. Nova Scotia Power continues to rely on frequent rate increases to manage costs, rather than delivering stability and predictability for customers. This pattern has real consequences. Customers are not given time to absorb one increase before the next one arrives. The result in ongoing uncertainty, repeated rate shock, and an erosion of trust in our electricity system.

Throughout 2025, Nova Scotians have dealt with the fallout of Nova Scotia Power's cyber security breach; this is a breach that the Board is also currently investigating. I hear from residents daily who are receiving irrationally higher estimated bills and cannot get clear answers about billing accuracy or when refunds will be issued. This unpredictability is more than an inconvenience; for families, it is a financial shock.

Nova Scotia Power's issues go beyond the cyber security breach and repeated rate increases. Nova Scotians continue to experience frequent unplanned outages and lengthy restoration times, despite paying some of the highest electricity rates in the country.

Just for one example, this last summer in July, power went out for 11,000 customers in Inverness for 24 hours, impacting residents and businesses during the peak part of the tourist season.

These are not isolated incidents. For each of the past eight years, Nova Scotia Power has failed to meet reliability targets and has been fined as a result. Despite repeated assurances, services have not improved.

For businesses, particularly small and rural businesses, power interruptions halt operations, damage equipment, and cut into their bottom line. When electricity is both expensive and unreliable, it becomes a serious drag on economic growth.

Coal remains one of the most expensive and volatile sources for electricity generation, yet Nova Scotia continues to rely on it heavily. While there is a legislative requirement for Nova Scotia Power to phase out coal, delays have prolonged exposure to high fuel costs and increased risks for customers.

These challenges are not solely the

result of the utility’s failures. They’re also the product of misguided decisions by the current provincial government. This government has failed to make the timely and strategic investments to modernize the grid, accelerate the transition away from coal, and deliver a reliable, affordable electricity system. Instead, the costs of delay have been downloaded on the customers through repeated rate increases, and when the government has stepped in with loans or investments, these interventions have been temporary. Temporary relief is not suitable for long-term planning.

I don’t raise these issues simply to attack Nova Scotia Power but to establish the full context in which this Rate Application is taking place. In that context, it is impossible to look at the state of electricity in Nova Scotia and conclude that Nova Scotia Power deserves more money from ratepayers to continue providing an unacceptable level of service.

[9:19:55] The Board has a responsibility to protect ratepayers while also providing stability for power rates over the coming years. So one of the central arguments our caucus is making today is that Nova Scotia must move away from constant reactive rate increases and toward a stable multiyear rate plan. Other jurisdictions have already recognized this reality. Jurisdictions such as New York, California, Hawaii, and Australia have adopted multiyear rate plans.

While no two models are identical they share common goals of stability, predictability and accountability. Multiyear rate plans set clear limits on what utilities can charge over a defined period. Annual adjustments are tied to inflation and anticipate efficiency improvements rather than repeated *ad hoc* rate increases. This approach creates incentives for utilities to improve efficiency, control operating costs, and make prudent investment decisions.

Nova Scotia Power’s mistakes and cost overruns should be paid by the company and its shareholders. A multiyear rate plan will prevent these costs from being passed on directly to customers while still allowing utilities to recover reasonable costs and plan investments responsibly.

Importantly, Nova Scotia Energy Board already has legal authority to do this. Section 64(a)2(b) of the *Public Utilities Act* explicitly empowers the Board to, quote, "order a staged or multiyear general rate increase."

If we look at the Regulatory and Appeal Board's recent decision to reject a substantial rate increase proposed by Halifax Water we see that the Board recognized that ratepayers should not experience rate shock as a result of imprudent choices made by utility, and reaffirmed its obligation to ensure rates are just and reasonable.

I urge the Board to do the same and use their authority to move toward a five-year power rate plan for Nova Scotians. A five-year plan would provide households and businesses with predictable electricity costs allowing for better budgeting and long-term planning. It would give businesses confidence to invest and expand and would impose appropriate discipline on the utility requiring it to manage costs within a defined framework instead of returning repeatedly to customers for relief. This is a proven regulatory tool, and it is one Nova Scotia should have adopted years ago.

I urge the Board to do everything within its authority to minimize this requested rate increase, to recognize the financial burden that this has already placed on Nova Scotians, reliability challenges they continue to face, and the urgent need for predictable and stable power rates. And most importantly, I urge you to use the authority granted to you by the *Public Utilities Act* to move Nova Scotia toward a five-year multiyear rate plan that delivers stability, transparency, and fairness. Nova Scotians deserve an electricity system that works for them, not one that asks them year after year to pay more for less.

Thank you.

THE CHAIR: Thank you, Mr. Rankin.

I next call on the Nova Scotia New Democratic Party Caucus.

OPENING STATEMENT BY NOVA SCOTIA NDP CAUCUS

MS. CHENDER: Hello. My name is Claudia Chender, she/her. I am the MLA for Dartmouth South and the leader of the Official Opposition for Nova Scotia. Thank you for the opportunity to present today.

Nova Scotians have shown incredible resilience, fortitude, and patience over the last few years as costs for homes and groceries and utilities have skyrocketed. We work hard and we should be able to build a good life for ourselves and our families, and this is germane to the issue in front of the Board today. Too often this context means that people are making hard choices to make their dollar stretch, choices that they should not have to make.

Since 2021 our power bills have risen by an average of $400, and as we’ve already heard 43 percent of Nova Scotians are paying more than they can afford to keep their lights on and their homes heated.

We’re here today to discuss Nova

Scotia Power’s Rate Application, an Application that would increase power rates by another 8 percent over the next two years and would push peoples bills up $600 compared to 2021.

If this increase is approved it would mean that Nova Scotia Power’s profits would hit 212 million by 2027, a 50 percent increase in just four years.

Nova Scotia Power is asking people to pay more while their corporate profits increase, and service, in many cases, decreases. Meanwhile household income is stagnant, power is unreliable, our data has been breached, and trust in the utility is at an all-time low.

We’ve heard from Nova Scotians across the province, our constituents, parents, students, business owners, farmers, seniors who tell us that they cannot afford more increases on their bills. Following the recent data breach that saw Nova Scotia Power fail to protect peoples’ personal information, including social insurance numbers that the company never should have had to begin with, people are dealing with the estimated bills double and triple what they actually owe, and they are, in many cases, paying those bills to the benefit of the company. It is generally the responsibility of government, and currently of this Board, to ensure that public utility rates, services, and practices are just and reasonable. The proposed rate, the terrible service, and these lax practices do not meet that threshold.

Power is an essential service. It’s essential for many of us for heat, for lights, but it is also essential to keep people connected through their phones and computers for work, school, and life in general. It’s essential for emergency services. Nova Scotians already spend 30 percent more on their home energy bills compared to the average Canadian, and a residential customer in Halifax pays double the energy rates of someone in Winnipeg or Montreal. At a time when half of Atlantic Canadians are within a couple of hundred dollars of being unable to pay their bills, people cannot afford to pay more.

Nova Scotia Power is a private company. Because the service they provide is essential, we regulate them to ensure that people can afford their bills and that the company isn’t passing on more costs to customers than is reasonable and appropriate.

As the Official Opposition, we have been urging government to step in to ensure that people can afford the power they need. Government has the regulatory tools to make many changes, including an additional rebate for customers, an affordable power rate, which you heard about in more detail from a previous presenter, and the ability to strengthen performance-based regulations and renewable energy standards so that the company can pass on savings from using cheaper renewable energy sources.

The government should also initiate a fulsome review of the company and its ownership structure, including both transmission and distribution, to determine how best to serve Nova Scotians going forward.

So far the current government has refused to take any of these steps, and against this backdrop it is vital that the Board review this Application with affordability top of mind and take steps wherever possible to ensure that the company is working in the best interest of their customers as required by Regulation.

For eight years in a row Nova Scotia Power has failed to meet reliability standards. In 2024 there was an unplanned power outage in Nova Scotia nearly every day; parents waking up in the dark having to get their children ready for school and themselves ready for work, business owners having to send staff home and losing working hours with no explanation, yet the fines for this failure are a slap on the wrist for a company making hundreds of millions in profit.

In the last year, rather than invest in more sustainable, affordable and reliable energy sources, the company has increased their use of coal and spent $55 million more on fuel and energy, passing these costs onto Nova Scotians. We ask the Board to examine the costs that the company is passing on to customers and ensure that those costs are just and reasonable. For example, Nova Scotia Power is paying an industrial carbon tax for not meeting emissions targets, and that is being passed on to customers. These costs are avoidable and should not be justified as a cost of doing business. The utility should not be allowed to pass on these costs to consumers. If Nova Scotia Power is not required to pay these costs from their profits, we argue they will continue to pass them on to customers and will not be incentivised to make the choices that serve those customers to ensure that power is more affordable and sustainable for Nova Scotians.

People need to be able to afford their power. This is not a nice idea; it is, as you've heard from all of the presenters so far today, an absolute necessity. This Board has the power to review this Application, and to ensure that this company's services, rates, and practices are reasonable and just.

[9:30:00] Nova Scotians have lost trust in Nova Scotia Power, and it's not hard to understand why. We urge this Board to do everything in its power to ensure that Nova Scotians have affordable, reliable power, and that the utility is held to the standard of ensuring that they work in the interest of the public.

Thank you.

THE CHAIR: Thank you, Ms. Chender.

Nova Scotia Power.

MR. CLARKE: Mr. Chair, again, I'll ask you about process here. We can go to the Opening Statement; we can swear in the panel, go through the introductions, then the Opening Statement. Again, it's at your pleasure what you'd like to do.

THE CHAIR: I wasn't 100 percent sure if it was intended to be a party or a panel Opening

Statement or a counsel Opening Statement. So if it's intended to be a panel Opening Statement, then yes, I think we can move forward to affirm the witnesses, and you can -- you can do then after that whatever order you prefer.

MR. CLARKE: So what we could do, is we could swear in the panel, I could go through the introductions, and then Mr. Williams could give the Opening Statement, if that's okay with you.

THE CHAIR: Sounds perfect. Thank you, Mr. Clarke.

Okay. So we'll just affirm the panel, then. So beginning with Mr. Flemming.

CRAIG FLEMMING, Solemnly Affirmed:

BLAKE WILLIAMS, Solemnly Affirmed:

MICHAEL WILLETT, Solemnly Affirmed:

ANDREW BLAIR, Solemnly Affirmed:

THE CHAIR: Thank you.

Take it away, Mr. Clarke.

MR. CLARKE: Thank you, Mr. Chair.

And for Members of the Board, this is the Cost of Service Panel.

We'll start with Mr. Flemming.

EXAMINATION ON QUALIFICATIONS BY MR. CLARKE

Q. Mr. Flemming, you are the Senior Director of Finance for Nova Scotia Power; is that correct?

A. (Flemming) Yes, that's correct.

Q. Have you appeared before the Board as a witness in the past?

A. (Flemming) Yes, I have. I have appeared before this Board on a number of occasions during annual capital expenditure proceedings, and I was, as well, a witness for Nova Scotia Power's 2023 to 2024 General Rate Application.

Q. Can you please describe your background, qualifications, and experience.

A. (Flemming) Yes. I am a Chartered Professional Accountant. I hold a Master's of Business Administration degree from Saint Mary's University, and a Bachelor of Commerce degree with a major in finance from Dalhousie University.

I have been with Nova Scotia Power for 23 years in increasingly senior roles in various areas of the business, including customer operations, revenue operations, customer service, and finance.

Q. Thank you.

Mr. Willett. Mr. Willett, you are the Director of Regulatory Finance for Nova Scotia Power.

A. (Willett) That's correct.

Q. Have you appeared before the

Board as a witness in the past?

A. (Willett) Yes. I've appeared before the Board on a number of occasions, including annual capital expenditure plans, fuel matters, Annapolis hearing, and the prior 2023-2024 General Rate Application.

Q. Can you please describe your background, qualifications, and experience.

A. (Willett) I have a Bachelor of Commerce degree from McMaster University, a Master's of Business Administration from Saint Mary's University, and I am a Chartered Professional Accountant completing my Certified Managerial Accountant designation in Ontario.

I worked in manufacturing and the financial industry for approximately five years before joining Nova Scotia Power as Manager of Fuels, Accounting, and Reporting in 2009. I've continued to work for Nova Scotia Power in progressively more senior roles, including Senior Manager Fuels, Planning, and Performance; Senior Manager of Customer Experience; and Controller for Nova

Scotia Power.

I started in my current role as Director of Regulatory Finance in June of 2018. I have responsibility in that role for capital, financial, and rates-related matters.

Q. Thank you.

Mr. Blair. Mr. Blair, you are a senior consultant with Elenchus Research Associates; is that correct?

A. (Blair) Yes, that's right. For clarity, I moved to Power Advisory a couple of years ago, but I continue to work on Elenchus projects in a senior consultant role.

Q. Have you appeared before the Board as a witness in the past?

A. (Blair) I have not appeared before this Board. I've appeared before the Ontario Energy Board, and the New Brunswick Board.

Q. Can you please describe your

background, qualifications, and experience?

A. (Blair) Yes. I have a Bachelor's degree in Economics and Financial Management from Wilfred Laurier University, and a Master of Economics degree from Carleton University. I've been working in the energy and regulation industry for 10 years, mostly in the areas of cost allocation rate design.

In Ontario, I've prepared cost allocation evidence for over a dozen distributors, as well as the Independent Electricity System Operator and Hydro One, the principal transmitter in Ontario.

I've prepared evidence for four proceedings in New Brunswick Power -- for New Brunswick Power, and appeared as a witness there, as well as appearing as an expert witness in areas of regulatory accounts. I've also filed evidence related to cost allocation rate design in British Columbia, Alberta, Saskatchewan, and Manitoba.

I was actively involved in the Cost of

Service Study process, and prepared, along with my colleague, John Todd at Elenchus, the Cost of Service Consultation Report, which is submitted as Appendix 12B.

MR. CLARKE: Mr. Chair, Nova Scotia Power requests that Mr. Blair be accepted as an expert witness in the areas addressed in his evidence, including cost of service and the Cost of Service Study Consultation Report, GRA Appendix 12B, Exhibit N-9.

THE CHAIR: Was a CV filed as well?

MR. CLARKE: I don't recall. I'll have to lean on Mr. Blair on that.

MR. BLAIR: I don't believe so.

THE CHAIR: Any questions on qualifications or objections from any of the parties?

MR. MAHODY: Mr. Chair, I just have a couple of questions.

THE CHAIR: Mr. Mahody, go ahead.

CROSS-EXAMINATION ON QUALIFICATIONS BY MR. MAHODY

Q. And Mr. Blair, the absence of a CV makes this a bit challenging, but can you tell me if in any of those occasions in the other jurisdictions, Ontario and New Brunswick, Alberta and the two listed, was your evidence accepted as expert testimony in each and every one of those applications?

A. (Blair) It was often joint work with my colleague, John Todd, who has expert evidence. I was specifically qualified as an expert witness in New Brunswick. And in Ontario, it was a bit of a strange of process where I was the sole member of an expert panel in a typical conference that did not go to oral hearing, so I was not specifically qualified as an expert witness, but it was accepted as expert evidence.

Q. And Mr. Blair, I take it you would have a professional résumé available to you ---

A. (Blair) Yes.

Q. --- readily? Okay. Would you be

prepared to file that résumé as promptly as you can, perhaps at a break, perhaps, in this matter?

A. (Blair) Yes.

Q. Okay.

MR. MAHODY: I'd like to take that as an undertaking, and subject to that undertaking I have no further questions, Mr. Chair.

MR. CLARKE: Certainly.

THE CHAIR: So Mr. Blair's résumé will be filed as Undertaking U-1.

UNDERTAKING U-1 - To provide Mr. Blair's résumé. Also to confirm the other experts that are to appear have filed their résumés, and if not, to file them

THE CHAIR: Mr. Clarke, could you also just doublecheck to make sure that the other experts that will be appearing in later panels, that their CVs have been filed as well, and if not, could you file them?

MR. CLARKE: Certainly.

THE CHAIR: Thank you.

Mr. Deveau.

QUESTIONS ON QUALIFICATIONS FROM MEMBER DEVEAU

Q. Mr. Blair, just a few questions.

I had understood initially that you had -- I can't remember if Mr. Clarke or yourself said you had testified in front of the Ontario Energy Board and New Brunswick Boards. It might have been Mr. Clarke who said that. So just from your last statement in response to Mr. Mahody, you actually never did testify in front of the Ontario Energy Board; is that correct?

A. (Blair) I testified as a company witness in front of the Ontario Energy Board, but not as an expert witness.

Q. Okay, okay. And you were involved as an expert in some sort of settlement discussions, you said, in Ontario?

A. (Blair) Yes. It was linked to a specific issue related to cost allocation and transmission where I was part of an expert panel, but the only member of the expert panel, and our evidence was filed as expert evidence but did not go to an oral hearing, ---

Q. Okay.

A. (Blair) --- which is fairly common in Ontario. Very rarely does the application process go to an oral hearing.

Q. Okay. And when you testified as a company panel, did you testify as a member of the company or as an independent expert?

A. (Blair) As an independent -- as -- I was not an expert, an independent expert simply, but I was a consultant to the company, where it's clear I was not part of the company, but working on behalf of the company.

[9:40:10] **Q.** As a consultant.

A. (Blair) Yes.

Q. Yeah. And in what areas? What were you testifying about?

A. (Blair) Load forecasting.

Q. Load forecasting?

A. (Blair) On that one, yes.

Q. Not cost allocation.

A. (Blair) No, not cost allocation in that matter.

Q. Okay.

A. (Blair) The first one I mentioned related to transmission, that was cost allocation.

Q. Pardon me?

A. (Blair) It was cost allocation in the first matter that I mentioned.

Q. What was that first matter?

A. (Blair) Hydro One export transmission service charges.

Q. And was that the one in terms -- the settlement on the one issue, you mean, that matter?

I'm mistaken now. When you testified as a member of the panel, you -- that was not on cost allocation.

A. (Blair) That one was cost

allocation.

Q. But you were a consultant, but not -- you didn't testify as an expert.

A. (Blair) To clarify, there were two times I've testified ---

Q. Okay.

A. (Blair) --- in front of the Ontario Energy Board.

Q. Okay. So let's do the first one.

A. (Blair) The first one was the Hydro One export transmission service rate where I was on the expert panel and it did not go to a full oral hearing, so the technical conference where I testified but not in front of the panel -- the panel itself wasn't there. There was a presentation day the following week where the panel was there and asked me questions, but I was not qualified as an expert witness at that time. Just the nature of the proceeding there was not an oral hearing. And that was on the issue of cost allocation.

And then the second time was about load forecasts where I appeared as a company witness for EPCOR Distribution Ontario.

Q. And was that a -- were you qualified as an expert in that matter?

A. (Blair) No, I was not.

Q. So in neither of the two matters were you qualified?

A. (Blair) That's right.

Q. Okay. And then in New Brunswick, what was your involvement in that matter?

A. (Blair) In the matter that I was qualified as an expert was about regulatory accounts related to rate smoothing, deferring cloud computing costs, and a Point Lepreau deferral account to spread the costs over multiple years for outages.

Q. Okay. So that had nothing to do with cost allocation.

A. (Blair) Not explicitly, no.

Q. What do you mean not exclusively?

A. (Blair) Not explicitly, no.

Q. Was there ---

A. (Blair) There were some cost allocation implications of how costs would be deferred and recovered later. But it was not on the area of cost allocation.

Q. Okay. It was more related to rate design. Is that fair?

A. (Blair) Yes. Yes, it is.

Q. Yeah. But you were not qualified on cost allocation, cost of service matters.

A. (Blair) No, not specifically. It was a pretty broad qualification of regulation of electricity and natural gas utilities.

Q. Right. But it was not in relation to cost allocation or cost-of-service studies.

A. (Blair) That’s correct.

Q. Okay. And then I heard you

mention other jurisdictions. I think it was British Columbia and Alberta?

A. (Blair) Yes, that's right, as well as Saskatchewan, but that was not a regulatory process.

Q. Okay. So ---

A. (Blair) And Manitoba.

Q. And Manitoba and British Columbia?

A. (Blair) Yes.

Q. Okay. So what did you testify -- did you testify at hearings?

A. (Blair) No.

Q. Okay. So were you -- were you -- so you didn't testify at hearings in those matters at all?

A. (Blair) No. Manitoba we were scheduled to testify ---

Q. Right.

A. (Blair) --- (inaudible due to

speaking over each other) but they decided they didn't need us to come to the hearing.

Q. Okay. Thank you.

QUESTIONS ON QUALIFICATIONS FROM THE CHAIR

Q. If I followed the responses to the Vice Chair's questions correctly, this would actually be the first time you'd be formally recognized as an expert in specifically cost-of-service matters?

A. (Blair) Yes.

Q. Okay.

THE CHAIR: Mr. Clarke, could you sort of restate the way that you want the witness qualified, please?

MR. CLARKE: Yes. Nova Scotia Power requests that Mr. Blair be accepted as an expert witness in the area addressed in his evidence, including cost of service and the Cost-of-Service Study consultation report, GRA Appendix 12B, Exhibit 9N.

THE CHAIR: Any objections?

He's so qualified.

MR. CLARKE: Thank you.

DIRECT EXAMINATION BY MR. CLARKE

Q. Mr. Williams.

Mr. Williams, you are the Senior Director of Regulatory Affairs for Nova Scotia Power; is that correct?

A. (Williams) Yes, that's correct.

Q. Have you appeared before the Board as a witness in the past?

A. (Williams) No, this is my first appearance as a witness before the Board.

Q. Can you please describe your background, qualifications, and experience?

A. (Williams) Yes. I have a Bachelor of Arts in Political Science from Wesleyan University in Connecticut and a Bachelor of Laws from Queen's University. I'm a member of the Nova Scotia Barristers' Society, an inactive member of the Law Society of Alberta, and a past member of the Law Society of the Yukon, as well as the Law Society of Northwest

Territories.

Prior to joining Nova Scotia Power, I worked at the Bennett Jones law firm in Calgary, where I was a partner and represented oil and gas and utility clients in a variety of regulatory settings.

I joined Nova Scotia Power in late 2019 as counsel but have been in my current role as Senior Director Regulatory Affairs since April 2023.

Q. Mr. Williams, you and the various panel members from Nova Scotia Power have the responsibility for the evidence of Nova Scotia Power; is that correct?

A. (Williams) That's correct.

Q. And that evidence includes Nova Scotia Power GRA Application filed September 18, 2025 and noted as Exhibit N-3; is that correct?

A. (Williams) Correct.

Q. And all the -- all of the various attachments and appendices associated with that evidence and identified as Exhibit N-4; is that correct?

A. (Williams) Yes.

Q. And Nova Scotia Power's responses to information requests filed in November of 2025 and identified as Exhibit N-20 through 31; is that correct?

A. (Williams) That is correct.

Q. And is Nova Scotia Power's evidence true and accurate, to the best of your knowledge?

A. (Williams) Yes, sir, with the following correction to be made to Appendix 3A, which is contained in Exhibit N-5. And it may be helpful for us to bring that exhibit up.

And specifically, if we can go to PDF pages 13 and 14.

Q. Which pages?

MR. WILLIAMS: And I think -- when I said PDF pages, Mr. Goodine, I was mistaken. It's the -- at the top of the page, so it's actually PDF page 24.

Thank you.

And Mr. Chair, I'd just draw the Board's attention to line item C and then line item N on the following page. And as you'll see, both of those items are listed as being "in progress," but these were, in fact, both filed as part of the GRA, and so Directive C or line item C was filed as Appendix 3B and Directive N or line item N was filed within Appendix 3A at pages 8 to 12, which would be PDF pages 19 through to and including 22.

And that would be the only correction, sir.

MR. CLARKE: Mr. Chair, subject to any questions from you or other Board Members, Mr. Williams would give the Opening Statement for Nova Scotia Power.

THE CHAIR: Please proceed.

MR. WILLIAMS: Thank you, sir.

OPENING STATEMENT BY NOVA SCOTIA POWER

MR. WILLIAMS: At Nova Scotia Power, we have the responsibility and duty to provide Nova Scotians with safe and reliable electricity service. Our team is dedicated to delivering on this responsibility while managing operating costs and capital investments in the best interests of our customers.

As we plan for the increase in changing energy needs of Nova Scotians, we know that the reliability of the service we provide has never been more important to our customers. We remain focused on continuing to strengthen the reliability of our system, building resilience against increasingly extreme weather, supporting Nova Scotia's economic development, and achieving provincial and federal decarbonization goals.

[9:50:04] While meaningful progress has been made, we have significant work ahead to meet our customers' evolving needs and government climate targets.

This next phase of Nova Scotia's

energy transformation will be complex, and it is made even more challenging given the current inflationary pressures and the affordability challenges facing many Nova Scotians.

The cyber attack also presents a challenge. While Nova Scotia Power was the victim of a foreign sophisticated cyber attack, we know it has affected the trust we've built with our customers. I want to reassure the Board and all stakeholders that everyone at Nova Scotia Power is committed to continuing to work relentlessly on the full recovery of all systems and services, and building back the trust of Nova Scotians.

I also want to reiterate what we have previously stated, which is that the GRA does not include costs related to the cyber attack. The 2026 and 2027 revenue requirement forecast that forms the basis of the Application was developed prior to the attack and has not been adjusted in any way to account for costs arising from the attack.

We know that there is never a good time to request an increase in electricity rates and that even small increases can have big impact on families and businesses. We continue to work with government and other key partners to avoid or reduce the need for rate increases. As the Board is aware, Nova Scotia Power's recent efforts, along with those of the Province, on behalf of our customers, have included the identification, development, and execution of the $117 million fuel cost receivable that was sold to invest Nova Scotia, and the $500 million Maritime Link Federal Loan Guarantee, the adjustment to Sulphur Emission Regulations, beneficial financing arrangements in relation to the battery energy storage system, and the Nova Scotia-New Brunswick Reliability Intertie, and the proposed securitization for approximately $704 million in rate base.

The process Nova Scotia Power undertook to prepare and file this General Rate Application was robust, inclusive, and transparent, and involved the development of application materials for review and detailed discussion with customer representatives. This resulted in the exchange of hundreds of information requests and responses, and numerous meetings, technical sessions, and negotiations, all of which involved customer representatives and their chosen expert consultants.

The results of this process is a consensus Application that has been put forward for the Board's consideration. In Nova Scotia Power's view, achieving this alignment on the outcome sought in this Application demonstrates that the GRA is in the public interest and that the outcomes are just and reasonable.

The settlement represents an interest-based resolution to an integrated set of outcomes negotiated with Intervenors representing all major customer groups. Keeping the negotiated package together preserves the balance of trade-offs that made the agreement possible.

In making its ultimate decision on this Application, we ask that the Board consider the need to balance these trade-offs.

In this General Rate Application, we have outlined the company's work to fulfill directives from the Board's 2023/2024 General Rate Application decision. Included in this Application are an updated Depreciation Study and Land Loss Study, as well as an updated Cost-of-Service Study, which is the result of a comprehensive review of the cost-of-service methodology with customer representatives and the Board, which was initiated in December of 2023 and continues today in this hearing.

We appreciate the vital role of this regulatory process and welcome the opportunity to answer questions about the Application. This is a critical time in Nova Scotia's energy transition, and we want to thank all participants and the Energy Board for their considerable time, effort, and commitment to this important process. We look forward to our further participation in this process over the coming days.

Thank you, sir.

MR. CLARKE: Mr. Chair, the cost-of-service Panel is ready for questions.

THE CHAIR: Thank you, Mr. Clarke.

Consumer Advocate?

MR. MURPHY: No questions. Thank you.

THE CHAIR: Small Business Advocate?

MS. MacADAM: We have no questions for this panel. Thank you.

THE CHAIR: Affordable Energy Coalition?

MR. DUKE: We have no questions. Thank you.

THE CHAIR: Industrial Group?

MS. RUDDERHAM: We have some questions.

THE CHAIR: Thank you.

CROSS-EXAMINATION BY MS. RUDDERHAM

Q. Good morning. My name is Brianne Rudderham, and I'll be asking questions on behalf of the Industrial Group. I'll pose the questions to the panel, and I'll allow the panel to decide who is best to answer each question.

I'm going to start with reference to Synapse's evidence, consultant of the Board counsel. Has the panel reviewed the evidence filed by Synapse at Exhibit N-37 in this proceeding?

A. (Willett) Yes, we have.

Q. And Synapse provided evidence specifically in relation to the Cost-of-Service Study; correct?

A. (Willett) That's correct.

Q. Fair to say the main criticism is -- relates to the debate between using Minimum System versus basic cost or customer methodology?

A. (Willett) That's correct.

Q. Can you confirm that the issues that were raised by Synapse in their evidence, including the Minimum System versus Basic Customer methodology have already been addressed either in this proceeding or are planned to be addressed in a future proceeding?

A. (Willett) That's correct. As part of the Settlement Agreement, there is a provision around the filing of an Application in regards specifically to the Minimum System Study. And as outlined in the Application, there was a year-long consultative process which included numerous stakeholder sessions, DRs, and modelling exercises that were produced with all stakeholders, Board staff, and Synapse as well.

Q. So I guess just to confirm, then, the Minimum System versus Basic Customer methodology and the suggested use of the load carrying capacity adjustment in Synapse's evidence is currently carved out within the Settlement Agreement to be addressed at a future proceeding?

A. (Willett) That's correct. The agreement would agree to use the proposed cost of service for 2026 and 2027, with an Application in 2026 regarding the use in future periods of the Minimum System Study.

Q. Okay. I'm going to switch topics to the assumptions used in the Cost-of-Service Study filed specifically in relation to service of Port Hawkesbury Paper, which I'll refer to as PHP, as an above-the-line customer starting January 1. Can you just confirm that's the assumption in the current Cost-of-Service Study filed?

A. (Willett) Correct.

Q. And currently, today, PHP is being served as a below-the-line customer?

A. (Willett) That is correct.

Q. And that's on the ELIADC tariff which was recently extended to the end of 2026?

A. (Willett) Correct.

Q. Okay. So I want to clarify the differences between the assumptions that are used in this proceeding and then also that were filed in the recent PHP Above-the-Line Application, which is under Matter M12661.

MS. RUDDERHAM: Mr. Goodine, if you don't mind pulling up the exhibit from that proceeding, N-1, page 3, which I had emailed to you yesterday.

So I'm specifically looking at the excerpt starting at line 5, which I'll just read into the record. It says:

> It is intended that PHP will subscribe to this Tariff on, or before, January 1, 2027 as the current term of the Extra Large Industrial Active Demand Control (ELIADC) Tariff, under which PHP currently takes service, will expire at the end of 2026.

Do you see that there?

[10:00:00] **A.** (Williams) We do, yes.

Q. And whether PHP takes service under the below-the-line ELIADC or the above-the-line on the -- which I'll refer to as the ELID tariff, depends on the outcome of that proceeding; correct?

A. (Williams) Whether PHP takes

service under the new tariff would, yes, be subject to the outcome of that process.

Q. And given the timing of that Application, it’s clear that PHP is not going to be served on the above-the-line rate for at least several months in 2026; correct?

A. (Williams) Yes. I mean, ultimately that’s up to the Board and at their discretion, but that sounds like a reasonable expectation at this point.

Q. It’s possible that it could be for the whole year of 2026?

A. (Williams) Again, that’s a question probably -- that’s really up to the Board. I can’t give you much more than that, I guess, Ms. Rudderham.

Q. I’m just -- based on the excerpt that we just read in that it could be on or before January 1, 2027.

A. (Williams) I think what was intended with that passage was it's certainly no later than January 1, 2027.

Q. And it's possible that PHP may not be satisfied by the outcome of that proceeding at all and not be served at an above-the-line tariff?

A. (Williams) Yes, that's correct, and that if we wanted to refer to the Settlement Agreement that possibility of the potential for that is accounted for in the Settlement Agreement.

Q. Just to clarify, the difference between the costs allocated to PHP as an above-the-line customer and as a below-the-line customer is proposed to be collected and recovered from other above-the-line customers in a deferral account; correct?

A. (Wiliams) That's correct.

Q. So I have just a couple questions on the deferral account itself. If PHP does not take an above-the-line service, does NSPI currently have a below-the-line Cost-of-Service Study that would form the basis of a true-up calculation in the deferral?

A. (Williams) The basis for that true-up would be the ELIADC, the tariff that PHP is currently taking service on.

MS. RUDDERHAM: Mr. Goodine, if you don't mind pulling up Exhibit N-27, which is NSPI's responses to NSEB IRs, and I'm specifically looking at IR-130 subsection (e), which starts -- the question is on PDF page 543. Perfect.

BY MS. RUDDERHAM:

Q. So Board asked for the best estimate of the amount deferred by month if PHP does not take service under the above-the-line tariff in the test years.

MS. RUDDERHAM: And, Mr. Goodine, if you don't mind scrolling to the answer, which is on PDF page 545. Right there.

BY MS. RUDDERHAM:

Q. I’ll just read it into the record starting at line 9. It says:

> In order to provide a credible monthly forecast of the PHP Deferral, [NSPI] would need to know the corresponding alternative [rate] under which PHP would take service (whether that is above the line or below the line.) Given that this remains to be determined, it is not possible to provide a credible estimate of the amount deferred by month, if PHP does not take service under [the] above the line rate in accordance with the assumptions included in the GRA.

So I believe you just confirmed that the true-up would be based on the ELIADC which is currently in place; correct?

A. (Williams) Correct.

Q. And now that it’s been extended, could NSPI now calculate the forecasted deferral amount to be charged to other customers if PHP remains on that rate for all of 2026 or 2027?

A. (Williams) So I think, Ms. Rudderham, that’s one part of it, and that’s the issue that’s been raised in the response. The other part of it would be the new tariff. So to understand what the true-up is you would need to know what you're truing-up to.

Q. I believe what you had just said was that the true up would be based on the ELIADC. So I'm wondering if that calculation can be done using the ELIADC as the assumed rate that PHP would be served on.

A. (Williams) Sorry; so the suggestion would be that rather than taking service under the -- a new above-the-line tariff, that there is no service ever taken on above-the-line tariff and that the ELIADC remains in place for the entirety of 2026?

Q. Yeah. So I'm trying to understand what that deferral would be. So currently that true-up would be based on the ELIADC for the months that PHP's currently being served on that rate; correct?

A. (Williams) Correct.

Q. So I want, I guess, the forecasted deferral amount if PHP was to continue to be served on that rate for all of 2026.

A. (Williams) Okay.

Q. Would you be able to provide that as an undertaking?

A. (Williams) Yes, we can do that.

Q. Thanks.

THE CHAIR: I've been asked by the court reporter just to make sure that people when undertakings are given just repeat and confirm exactly what they are so it's easy for them to identify those. So could you just restate exactly what you're looking for, and we'll mark it Undertaking U-2.

MS. RUDDERHAM: So I was asking for NSPI to provide a response to Board IR-130(e), which is to calculate a forecasted deferral amount to be charged to customers if PHP remains on the ELIADC for all of 2026.

MR. WILLIAMS: I confirm. That's in alignment with my understanding, sir.

THE CHAIR: Okay. That will be Undertaking U-2.

UNDERTAKING U-2 - To provide a response to Board IR-130(e), which is to calculate a forecasted deferral amount to be charged to customers if PHP remains on the ELIADC for all of 2026

BY MS. RUDDERHAM:

Q. I have other questions on the deferral account, but I assume it's best left for Panel 4 for more general regulatory other than cost of service. They're not directly related to cost of service.

A. (Williams) I think that we could -- it's going to be a very similar panel, but I think that's probably best.

Q. Okay. This is also on the topic of the PHP alternative tariff in matter M12661, but I wanted to clarify what appears to be an outstanding dispute as between NSPI and PHP which is described in the

Application.

MS. RUDDERHAM: Mr. Goodine, if you don't mind pulling up that exhibit from M12661, Exhibit N-1, page 6, and I'm looking specifically at lines 9 to 19.

MR. GOODINE: You didn't send that, though, right?

MS. RUDDERHAM: Oh, that's the same one that you had pulled up earlier. Apologies for the confusion. Page 6.

THE CHAIR: Did you want that item marked as an exhibit in this proceeding, Ms. Rudderham?

MS. RUDDERHAM: It's currently public record on the Board's site. I don't feel it's necessary unless, Mr. Chair, you do.

THE CHAIR: That's fine.

BY MS. RUDDERHAM:

Q. So, panel, I'm looking at lines 9 to 19. I don't believe I need to read it out. But it outlines that the assumptions used in the Cost-of-Service

Study relating to PHP's service; they're just summarized in there. I see you nodding yes.

A. (Williams) Yes.

Q. And PHP has used the forecast of 65 megawatts for modelling PHP's demand at 3CP in the Cost-of-Service Study.

A. Nova Scotia Power has, yes.

Q. Yes. Now, I wanted to just clarify one portion of that paragraph, which is lines 15 to 19, which I'll just read in.

> The Company understands that PHP's view is that the three coincident peak demand determinants applicable to PHP should be set at the firm demand level of 8 [megawatts] in light of the Company's control of PHP's load at times of system peak. In light of the provisions of the GRA Settlement Agreement and well-established [Nova Scotia] Power cost of service treatment, the Company does not agree.

Are you able to clarify what exactly this dispute is about? I guess I'm -- it's not abundantly clear. Are you able to just clarify?

A. (Williams) Yes. I don't believe

I can add a whole lot more than what's contained in those lines 15 or 16 through to 19. But what we're talking about is the use of 65 megawatts as PHP's firm interruptible load. The PHP -- and I don't want to speak for PHP, but I believe there's a view that it should be something different than that and the company is simply just stating that in light of what was agreed to in the Settlement Agreement and in light of the basis for establishing that 65 megawatt number in the Settlement Agreement, which is in reference to the well-established Nova Scotia Power cost of service treatment, the company does not agree with using something different than 65.

Q. I guess just to clarify, then, it's the difference of the interruptible load of 57 megawatts, that's what the discrepancy's about in the cost of service? The eight is the firm?

[10:10:16] **A.** (Williams) No, and it's a fair question you're asking, Ms. Rudderham. But just to be clear, it's using eight instead of 65.

Q. And PHP was a signatory on this Settlement Agreement?

A. (Williams) They were.

Q. And if PHP is successful in that separate proceeding of setting it at 8 megawatts, are you able to explain how that would impact rate revenues to be recovered from other customer classes compared to what's currently filed in the GRA?

A. (Williams) I'm not at this time, and I think it would depend on the rationale and how that decision was arrived at or how that outcome was arrived at.

Q. Sorry. You're saying the rationale would change the outcome if it was set at 8 megawatts, or are you just saying whether it would be set or not?

A. (Williams) I'm just suggesting that -- your question was if they are successful and it's set at eight. I would expect that how eight was arrived at in that proceeding may have some bearing on the impact.

Q. I guess, then, is NSPI able to provide an updated cost of service to reflect what PHP's requesting to have its demand at 3CP be set at eight rather than 65 so we could see what the impact on other customers would be?

A. (Williams) I think it would be most effective and most appropriate to do that as part of the PHP Application proceeding, Ms. Rudderham, not as part of this proceeding.

Q. Okay. I was going to ask for an undertaking on that. Are you saying you cannot or won't provide that as part of this proceeding?

A. (Williams) I'm making the suggestion to you that it's likely more appropriate in that proceeding than this proceeding.

Q. Okay. I do want to ask for an updated version with that change.

A. (Williams) It's something we can

provide.

Q. Okay.

THE CHAIR: Again, Ms. Rudderham, if you can just kind of restate the full request for the record.

MS. RUDDERHAM: The request is for an updated version of the Cost-of-Service Study to reflect the change to PHP demand at 3CP, which would be at eight rather than 65, which is currently modelled in the Cost-of-Service.

I believe that would be an update to Exhibit N-21(i) and (ii), which are filed confidentially, which are responses to CA IR Attachment 1 and 2.

MR. WILLIAMS: I did not have the time to go and look at those specific exhibits, sir. I'll take it subject to check that those are accurate, and I believe we understand the essence of the undertaking.

THE CHAIR: Thank you. That will be Undertaking U-3.

UNDERTAKING U-3 - To provide an updated Cost-of-Service Study in Exhibit N-21(i) and (ii) to reflect the change in PHP demand at 3CP

MS. RUDDERHAM: Thanks.

BY MS. RUDDERHAM:

Q. Would that change for PHP demand at 8 megawatts versus 65 megawatts at 3CP, would that have an impact on the revenue-to-cost ratios for other customers?

A. (Willett) I would expect it would have.

Q. Would NSPI be able to provide that change to the RC ratios?

A. (Willett) I'm just hesitating because there is a process that has to take place to establish those RC ratios and I'm just wondering, is your question what would there ---

Q. Perhaps I'll just put it to you like this.

Would it increase the RC ratios for other customers, generally speaking?

A. (Willett) We would have to go through the analysis, but that would be my expectation.

Q. Okay. I don't think I need an undertaking on that because I understand it would take some time.

MS. RUDDERHAM: Those are all my questions. Thank you.

THE CHAIR: Thank you.

Municipal Electric Utilities?

MR. MacDUFF: No questions, Mr. Chair. Thank you.

THE CHAIR: Department of Energy.

MR. BOYLE: No questions, Mr.

Chair.

Thank you.

THE CHAIR: Liberal Caucus?

MR. RANKIN: No questions.

Thank you.

THE CHAIR: New Democratic Party Caucus?

MS. CHENDER: No questions.

THE CHAIR: Port Hawkesbury Paper?

MR. MacDOUGALL: No questions for this panel, Mr. Chair.

THE CHAIR: Renewall?

MR. ROSCOE: Yes, one minor question.

<u>CROSS-EXAMINATION BY MR. ROSCOE</u>

Q. Good morning. Dan Roscoe with Renewall Energy Inc.

As the province's only licensed retail supplier, we're -- the details of the General Rate Application are of great interest to us, especially the Cost-of-Service Study. One small question regarding Exhibit N-17 on -- and related to the attachments.

SR-1, Attachment 2 and SR-1, Attachment 3 have both been filed -- indicated that they're both partially confidential, but only confidential versions were filed. I would like to request if a redacted version of those two exhibits can be undertaken to be provided after this hearing.

A. (Willett) Could we just have that pulled up just so we can have a look?

<u>THE CHAIR:</u> Well, I think it's confidential.

MR. WILLETT: I apologize. Sorry.

(SHORT PAUSE)

MR. WILLETT: Yes, we could do that. It was an Excel file, so that was the reason for the filing in that manner, but we could do a PDF version.

MR. ROSCOE: PDF redacted would be helpful, from our perspective.

Thank you very much. No further questions from us of this panel.

THE CHAIR: Just we'll mark that as a formal undertaking, so just if you could restate exactly what you're looking for just for the record just to make it clear.

MR. ROSCOE: Sure. We are requesting redacted PDF versions of SR-1, Attachment 2 and Attachment 3, as noted on page 1 of Exhibit N-17.

MR. WILLIAMS: That's confirmed, sir. Thank you.

THE CHAIR: And that will be

Undertaking U-4. Thank you very much.

UNDERTAKING U-4 - To provide redacted PDF versions of SR-1, Attachment 2 and Attachment 3 as noted on page 1 of Exhibit N-17

MR. ROSCOE: Thank you, Mr. Chair.

THE CHAIR: Any party that I missed before going to Board counsel?

Mr. Mahody.

MR. MAHODY: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MAHODY

Q. Good morning, panel. Mr. Williams, I have one preliminary point, and you could choose to defer it if you wish. I commit to you the rest of my questions really are about cost of service, but in past General Rate Applications, the President of Nova Scotia Power has appeared before this Board and testified.

In 2022 that happened, in 2012, that happened, and it happened many years prior to that time. It occurred even in cases where full Settlement Agreements were being proposed. In this case, and correct me if I'm wrong, Nova Scotia Power is not putting forth anyone from the executive leadership team. Why is that?

A. (Williams) I think, Mr. Mahody, the reason for that -- and I'll maybe start by saying that Mr. Gregg is here this morning. The reason for that is that this process was a little bit different than past General Rate Applications, in that the Consensus Agreement was arrived at prior to filing. There was a lengthy process that was involved in that, obviously, and that's been discussed in -- there's information about that on the record. And we thought it most appropriate, given the unique nature of the process, the discussions that occurred, we thought it most appropriate and most helpful for the Board to have those members of the team that were directly and intimately involved in those discussions and then a negotiated outcome appear before the Board, so that we could provide the Board with what we felt would be the best information to aid them in making a decision.

[10:20:36] **Q.** But you appreciate that the Board has full discretion to accept some, all, or none of the consensus proposal?

A. (Williams) Certainly.

Q. And in that regard, this is a GRA; it is about setting the rates for Nova Scotia Power. In that circumstance, unlike all of the other previous GRAs dating back at least, by my count, to 2004, this is the first time we have no one from the executive leadership team appearing before the Board to testify about the Application. That's correct?

A. (Williams) You have members of the senior leadership team of Nova Scotia Power that were involved in negotiating the outcome and the Application that's before the Board.

Q. Okay. But in past GRA Applications, we've seen the President, we've seen the CFO, we've seen others. Members of the executive leadership team. They're not scheduled to be part of any of your witness panels; is that correct?

A. (Williams) I think I've answered it twice now, Mr. Mahody, there's -- the panel that is here and that we've provided notification of who will attend is a matter of record, I believe.

THE CHAIR: I think the question is, unlike rate cases that have occurred for the past two decades, in this particular instance, you can confirm that what is different is there's no executive leadership representation on any of the panels?

MR. WILLIAMS: Yes, sir, subject -- I don't know the representation of the panels going back that far, off the top of my head. But as I said, I think what is also different here is how this Application was developed, the consensus nature of it, the in-depth discussions that occurred leading up to the filing of the Application, and what we felt was important to have the people that were involved in those discussions, with customer representatives, hearing from them, their perspectives, as part of that process. We felt it was important to have those specific people here to speak to the matters before the Board, and we made that decision because we felt it was putting the Board in the best position to get the best information and the most accurate information possible.

THE CHAIR: And that decision then precluded anyone from the executive leadership team being on a panel?

MR. WILLIAMS: There were certainly executive -- members of the executive team that were involved with those discussions, not as on a regular basis as Mr. Willett, Mr. Flemming, and myself, and I'll also note that there's been a recent retirement that would remove one of those potential executive members from appearing.

THE CHAIR: Okay. Thank you.

BY MR. MAHODY:

Q. All right. On to cost of service. And I'd like to start with just identifying the disproportionate impact of the proposed rates among rate classes.

MR. MAHODY: And I begin by calling up -- Mr. Goodine, I've supplied a -- the announcement from Nova Scotia Power from September 2, 2025, announcing the settlement reached with customer representatives. Are you able to call that up, please?

Thank you.

BY MR. MAHODY:

Q. And can the witness panel just confirm that this is the Nova Scotia Power release from September 2 of 2025?

A. (Williams) That's confirmed.

MR. MAHODY: Mr. Chair, could we just get that marked as an exhibit?

THE CHAIR: That will be Exhibit N-43.

--- EXHIBIT NO. N-43:

Nova Scotia Power announces settlement reached with customer groups

MR. MAHODY: Mr. Goodine, if I could ask you just to scroll down? It's the paragraph, "If approved by the NSEB..." that I'm looking -- would like to refer the panel to.

BY MR. MAHODY:

Q. So Nova Scotia Power indicates:

> If approved by the [Nova Scotia Energy Board], overall average rates will increase across all

customer classes by 2.1 per cent in 2026 and 2.1 per cent in 2027 with [the] rates to be effective January 1 of each year. Residential rates are expected to increase by approximately 4.1 per cent in both ['26 --] 2026 and 2027.

What are the main drivers of why the residential rates are proposed to increase at approximately two times the average?

A. (Williams) I think Mr. Willett is going to respond to that, Mr. Mahody, but I think just to -- for clarity, rather than referring to the press release that we're referring, it's likely more helpful to refer to the Application, in terms of what the rate increases are.

Q. Sure. Thank you. And my question isn't about is it 3.9, or 4.1, but the idea that it's a significantly greater impact on the residential class. I'm just looking for the main drivers about why that has occurred.

A. (Williams) Yeah, I understand. I think Mr. Willett can respond to that.

A. (Willett) Thank you for the

question.

As my colleague mentioned, I'll just make sure the appropriate increases are on the record. So for the domestic class, it's 3.8 and 4.1, and on an overall average basis, it's 1.8 and 2.4 percent, which can be found in Figure 2.1.

To answer your question about what is driving the difference between the average increase for all customers and the increase faced by the domestic class, I just want to first acknowledge that in every General Rate Application, you update the revenue requirement, and you update the usage statistics for each individual customer class. There is always going to be a discrepancy between the class average and individual class levels. We have a response to an IR that might be helpful to bring up, which is NSEB IR-131.

Q. N-27, I believe, Mr. Willett, is that where we are? Board's IRs? I think we have it up, Mr. Willett. If we can just get the IR number again?

A. (Willett) Perfect. So this response outlines the three areas which are the main drivers of the discrepancy between the average class impact versus the domestic class impact. So I'll just talk about the second point first.

So there's a higher increase in the domestic class contribution to the system peak. So what that means is that there's costs allocated to various customer classes based on how customer classes is using the system, and specifically, how classes are using the system during system peak events.

When we look at the last cost-of-service in 2023/2024 General Rate Application versus the cost-of-service completed for 2026/2027, what we have seen is that the domestic class is actually using the system more during system peak events than they were in the prior study. So we can see that it's increased by about 5 percent from that period to this period. That can be for a number of reasons, including, you know, installation of electric heating moving from oil; customer -- we've experienced significant customer growth in the domestic class. So those are reasons why that can increase, so that is one of the driving factors.

Also, which we'll be talking about, is point number 1, the change in the proposed cost-of-service methodology. So this was a Board directive coming out of the last General Rate Application to look at how the system is changing moving to 2030 when we're phasing out coal moving to more renewables. We hadn't had a cost-of-service proceeding in many years. I think it was over a decade since the last time we had reviewed all the ways we functionalize, classify, and allocate cost to customers.

[10:30:11] There’s been a number of proposed changes that have taken place as part of the cost-of-service, with the agreement of the stakeholder group. This was a year-long process, which customers and -- or the company and customer representatives went through, so that has resulted in changes that have allocated more of the costs to the domestic class.

And maybe I'll just step back for one second as well. When you're looking at a Cost-of-Service Study, you're looking at attempting to assign costs based on cost causation. And so that was the core for development of this cost-of-service, looking at how things have changed and ensuring that we're assigning costs based on cost causation. So there has been more costs allocated to the domestic customer class based on the cost-of-service and based on those principles of cost causation.

Q. And of those factors that you indicate in this IR response, you agree with me that factor one is the lion's share of the reason why the domestic class is moving in the direction that it is.

A. (Willett) So I would say, I agree, it's the largest contributor of the three factors that are listed. There are changes in the cost-of-service methodology and the Line Loss Study, specifically, that helped the domestic class as well. So Line Loss Study produced lower line losses for the domestic class, that was an item that benefitted, but that there are items that have shifted cost responsibility to the domestic class based on that cost causation.

Q. And Mr. Blair, you agree that cost-of-service studies are used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers.

A. (Blair) Yes.

Q. In effect, the Cost-of-Service Study seeks to determine what costs are incurred to serve each class of customers.

A. (Blair) Yes, that's the goal.

Q. And the Cost-of-Service Study involves three steps. The first is to functionalize, where costs are functionalized by separating utility plant and expenses according to the primary function they serve, generation, transmission, or distribution. Is that the first step?

A. (Blair) Yes.

Q. Okay. The second is classification, where functionalized rate base and operating costs are classified based on their primary cost drivers, energy related, demand related, or customer related. Is that correct?

A. (Blair) Yes.

Q. Okay. And then finally, costs are either directly assigned to specific customers or allocated among customer classes according to allocation factors based on energy use, peak demand, and customer accounts.

A. (Blair) Yes.

Q. Okay. And when selecting classification factors, or allocators, the goal is to fairly allocate the costs among different customer classes based on cost causation?

A. (Blair) Yes, that's correct.

Q. Mr. Willett, you mentioned a few moments ago about the Board directing a cost to be completed coming out of the last Rate Application, the decision -- hearing in 2022, a decision in early 2023. And the Board directed that the Cost-of-Service Study be undertaken and be filed in time for the next GRA and no later than the end of 2025. Is that your recollection?

A. (Willett) Subject to check, yes.

Q. Okay. And can you describe for me the process that NSP followed to perform that direction from the Board.

A. (Willett) Yeah, I can discuss, and I'll ask my colleague, Mr. Blair, to jump in if I miss anything.

But we opened the process with the Board back in December of 2023, and throughout 2024 we would have had numerous stakeholder sessions with customer representatives, their experts, and on behalf of Nova Scotia Power we had Elenchus, who was facilitating those discussions.

Reflecting on those discussions, this was an opportunity for Intervenors to gain a better understanding of the cost-of-service employed at -- the current cost-of-service employed at Nova Scotia Power, the history of the cost-of-service at Nova Scotia Power, and also for Nova Scotia Power to hear from customer representatives and their experts about challenges that they have with Nova Scotia Power's cost-of-service that was employed at the time.

Also, it was an opportunity to look at the changing system, the Path to 2030. What is changing on the system as we phase out coal over time, add more renewables to the system, and how has that impacted the way we are doing the cost-of-service?

So we went through that process. We initiated an extensive data request process as part of that proceeding. We filed that as evidence in our appendix for the cost of service. I believe there was over 150 data requests. We had somewhere in the range of 50 to 75 extensive modelling exercises that were reviewed with stakeholders as well. And that resulted also in a two-day session that was facilitated by Bruce Outhouse, who is very familiar to this Board, to try and come to a consensus on a number of the items of the cost of service.

Following that process, the analysis was all done on historic 2023 cost-of-service data. So one of the items that was identified as a concern for Intervenors was understanding the impact of the cost of service on an actual future revenue requirement or the General Rate Application that's in front of the Board today. So they wanted to see those impacts, and that's when we started to have the General Rate Application discussions about the revenue requirement and the cost-of-service impacts on that revenue requirement, and it resulted in the overall Settlement Agreement with stakeholders.

Q. And Mr. Willett, the involvement of Mr. Outhouse that your evidence speaks of, that was related to a two-day session administered by Mr. Outhouse in November of 2024, and perhaps a half-day in December of 2024. Is that your recollection?

A. (Willett) Subject to check. I recall the two day for sure, I'm just -- your reference to a half-day, I'm not sure which one that was in 2024 as well. But I take your word for that.

Q. No, understood. But in any event, Mr. Outhouse's involvement was during that period of the discussions. It didn't occur before that or extend after November or December of 2024; is that correct?

A. (Willett) So I would say he was involved in listening into prior stakeholder sessions, but in those November sessions, that's when he would have been facilitating those sessions, the two-day session.

Q. Sure. And you recall that in the

two-day session in November of 2024, I attended, along with Board staff and Synapse as well.

A. (Willett) That's correct.

Q. But that the discussions among the utility and the intervenors continued after that time with no involvement from Board staff or Synapse in relation to cost of service.

A. (Willett) That's correct.

Q. Okay. And eventually, those discussions among the utility and the Intervenors culminated in what Nova Scotia Power refers to as the Consensus Agreement.

MR. MAHODY: And Mr. Goodine, if we could call up Exhibit N-27, page 1, please?

BY MR. MAHODY:

Q. So this is the request to file a copy of the Consensus Agreement reached with customer representatives.

MR. MAHODY: And if we could scroll

down to the next page?

BY MR. MAHODY:

Q. Just first off, can I ask the panel, the Consensus Agreement was filed in this matter as a result of an IR that was asked by the Board. Did the company have a reason for not filing the Consensus Agreement with its Application?

[10:40:04] **A.** (Williams) The decision was made not to, Mr. Mahody, but in hindsight, we probably should have filed it with the Application. The distinction, as we saw it, was that this was, as I referred to earlier, different than past settlement agreements, in that there had been a consensus that had been reached that resulted in the filing of the Application, so the Application stood on its own, as opposed to past settlement agreements, and most settlement agreements in a regulatory context, where it happens subsequent to the filing. You're actually -- you're settling something, as opposed to putting forward a Consensus Application. That was the distinction as we saw it. But yeah, in hindsight, we could have filed it with the Application.

Q. When I look, for instance, Mr. Williams, at the extensive amount of standardized filings that the company makes, and I appreciate works very hard in order to prepare and file, and you stack up some of that information with a Consensus Agreement, it would strike me that for the same reasons standardized filings occur to make sure the information gets out the soonest time possible, this Consensus Agreement falls into that same rationale; does it not?

A. (Williams) I'm not sure I'm entirely following the question. Maybe can you ask me again?

Q. The Consensus Agreement is a material document in relation to this Application; is it not?

A. (Williams) There's some aspects of it that certainly are material, and I would say material to the Application. I believe every aspect that is -- or I would view as material was included and described in the filing itself. So I don't believe the filing would have been missing any of this information, but certainly I take your point. And like I said, in hindsight, I think we would -- if we were doing this again, I think we would file the Settlement Agreement as part of the Application.

MR. MAHODY: Mr. Goodine, could we turn to PDF 11 of this exhibit, please? And so -- and if we can just scroll down to see the column "Cost of Service"?

BY MR. MAHODY:

Q. And so here, in the cost-of-service section, it indicates:

> The cost of service as set out in the draft GRA will be included in the 2026 GRA and put forward for approval, subject to the following:
> a) Use of the minimum system methodology after the 2026/2027 test period will be subject to a future proceeding and determination by the Board for which an Application will be made in 2026,

and in which parties agree to take any position they so choose... (As read)

And I did want to spend a few minutes getting some clarification on this proposed Minimum System methodology.

MR. MAHODY: And Mr. Goodine, I'd like to make reference to Ms. Palmer's Synapse testimony, N-37, PDF page 5, please. PDF 7. PDF 7. Sorry, Mr. Goodine.

BY MR. MAHODY:

Q. All right. And here, beginning at line 5 on that page, Mr. Blair, this is for you, Ms. Palmer indicates:

> The minimum system study is a cost analysis that estimates what the cost of the distribution system would be if all poles, fixtures, and wires were sized to minimum specifications. [Nova Scotia] Power considers the cost of a hypothetical system made up of minimum-sized equipment to be customer-related, reasoning that ...'cost of a system with minimal demands...approximate(s) the cost of serving each customer if there were no capacity constraints.' The Company considers the remaining cost of the actual distribution system 'to be the portion of costs incurred to meet peak demands' and thus to be demand-related.

Has Ms. Palmer accurately set out the Minimum System method, Mr. Blair?

A. (Blair) Yes, it's a good description.

Q. And as you know, Mr. Blair, Ms. Palmer recommends that the Board direct the company to discontinue the Minimum System method and adopt the Basic Customer method to classify distribution costs?

A. (Williams) I think to be fair, Mr. Mahody, Ms. Palmer's conclusion is she doesn't oppose the Settlement Agreement, and therefore that she recommends:

> ...the Board find that certain [cost-of-service] methodologies put forward in this case be revisited in the next GRA.

Q. But as a matter of cost-of-service, Ms. Palmer recommends the use of the Basic Customer method; is that correct?

A. (Williams) If you'd like to point me to an excerpt that you're referring to specifically. I just read from her evidence what her recommendation was.

(SHORT PAUSE)

MR. MAHODY: Mr. Goodine, could we turn to -- it's paper page 9. I'm sorry, I don't have the PDF. And it's line 23.

BY MR. MAHODY:

Q. Ms. Palmer states, "I recommend classifying distribution costs using the Basic Customer Method."

You acknowledge that that's her recommendation?

A. (Williams) I guess I recognize those words on page 9, sir, but in the conclusions, it's a bit of a different recommendation. I think that distinction is important for this proceeding in particular.

Q. Okay. Well, let me come at it this way, Mr. Blair. Has Nova Scotia Power calculated the impact on rates if the recommendation to utilize the Basic

Customer method is undertaken?

A. (Williams) Sorry, Mr. Mahody, can you just repeat the question? I just want to make sure we're getting it correct.

Q. Yes. Has Nova Scotia Power calculated the impact on rates if the recommendation to use the Basic Customer method is followed?

A. (Williams) Just one moment, Mr. Mahody. We're just trying to pull up a document for you.

A. (Blair) I think NSEB IR-128 is the appropriate reference your question.

THE CHAIR: That is N-27, Mr. Goodine.

MR. WILLETT: So the company has not produced rates related to the use of the system, but it has provided Attachment 1, which shows the impact in the Cost-of-Service Study.

BY MR. MAHODY:

Q. Okay. Can you take me to that, Mr. Willett?

A. (Willett) Attachment 1. You would have to open the Excel file.

Q. Okay.

(SHORT PAUSE)

BY MR. MAHODY:

[10:51:02] **Q.** All right. So can you point us to where this calculation and what it shows?

A. (Willett) Yes. Thank you.

So what this calculation is showing is in Column C through G, that is the Application in front of the Board. And what Columns J through L are showing would be the costs with costs classified 100 percent to demand instead of using the Minimum System Study. And the difference in cost allocation is shown in Columns M through O by customer class.

And there's a tab for each of the years 2026 and 2027, so we're looking at 2027 on the screen currently.

Q. And am I reading that correctly

where there's a reduction in Column R of 2.6 percent for the residential class?

A. (Willett) Two point six (2.6) percent of costs in the cost of service, correct.

Q. Okay. And that is -- is that, Mr. Willett, a 2.6 percent reduction from the $1.144 billion that's in Column G?

A. (Willett) Could we just flip to the 2026 one for a second?

Q. Yes, we can.

A. (Willett) Sorry. I'm just more familiar with the numbers on the '26 ---

Q. Understood, and the question's the same, so I appreciate it.

A. (Willett) Yeah. So you can see similar -- it's the 1 billion, 95 million, and it would be 1 billion, 65 million under the 100 percent demand, resulting in approximately $30 million reduction in costs which represents 2.7 percent reduction.

Q. And this exhibit also shows the corresponding increases that would occur for the other classes at 2 through 10.

A. (Willett) Increases in costs in the cost of service, but you have to remember there's also the revenue-to-cost ratio process that is undertaken, so that doesn't necessarily translate to what the rate impacts would be.

Q. Okay.

MR. MAHODY: So Mr. Goodine, could we now go back to Ms. Palmer's evidence, N-37? I'd like to go to Table 2, which in my paper copy it's page 16 at the bottom of the page.

Thank you. There it is.

BY MR. MAHODY:

Q. And so at least to the domestic class here, Mr. Willett, the impact of utilizing the Basic Customer method, I think we just looked at a 2.7 percent change. It's been estimated here in the range of 2 percent. That's what we're looking at?

A. (Willett) I haven't seen the support for the calculations here, so I can't speak to the calculations done by Synapse. But ---

Q. Sure. If you were making up this chart, though, based on what we just looked at, you would have 8 percent -- you tell me. What would you have for the domestic class and then what would you have under the Basic Customer? I thought the differential was the 2.7 percent.

A. (Willett) And that's what I alluded to, that you would have to go through the full process of the RC ratio in order to actually determine what the rate impact would be to each customer class. We have not done that exercise.

THE CHAIR: Mr. Mahody, if I could jump in just for a second?

Mr. Willett, that is a fairly stepwise process. You've laid out the methodology for taking it from the cost-of-service number to the RC ratios in the Application?

__MR. WILLETT:__ So for our proposal, we have done that exercise, yes.

__THE CHAIR:__ Right. But the methodology is -- it's stepwise. You've got standard methods that you use to determine that final RC number?

__MR. WILLETT:__ So there is, yes, a process and step. Yeah, correct.

__THE CHAIR:__ So you are able to take those costs that we just looked at that you produced for the exhibit, those cost differences, and put it into that stepwise process and come to the final RC ratios?

__MR. WILLETT:__ Yes. So yes, you could -- you could do that and then -- yes.

__THE CHAIR:__ And so will you undertake to provide that, to produce resulting rate impacts from the change in methodology?

__MR. WILLETT;__ Yes.

THE CHAIR: Okay. So just, then, for the record, so what the request would be, would be to take the cost changes that we looked at from NSEB IR-131, I think it was, that we just looked at, the schedule, and go through the exercise to find -- the stepwise exercise to produce new RC ratios and new resulting rates for the customer classes.

MR. WILLETT: And I would just correct. I think it was 128.

THE CHAIR: One twenty-eight (128), sorry.

Thank you.

And that will be Undertaking U-5.

UNDERTAKING U-5 - To take cost changes from NSEB IR-128 and go through the stepwise exercise to produce new RC ratios and new resulting rates for the customer classes

THE CHAIR: Sorry, Mr. Mahody.

MEMBER MURPHY: Could I just jump in on this since we're talking about it, Mr. Mahody, if you don't mind?

I just wanted to -- for that undertaking, I just wanted to be clear, the IR asked for that table to be provided under the assumption that 100 percent of the cost would be demand related. Would that match the Basic Customer methodology?

MR. BLAIR: The Basic Customer methodology isn't defined as one specific way to do it, so this is -- this could be considered a Basic Customer method, yes.

MEMBER MURPHY: So the information we get through this undertaking will represent rate impacts if the Basic Customer methodology was used.

MR. BLAIR: Yes. There could be some minor differences in different -- Basic Customer methods, but this would be representation of Basic Customer method, yes.

MEMBER MURPHY: Okay. Thank you.

MR. WILLIAMS: I'm sorry, Mr. Mahody, just before we continue, I just want to make sure I'm clear on what...

(SHORT PAUSE)

MR. WILLIAMS: My apologies, sir. My apologies, Mr. Mahody.

MR. MAHODY: Mr. Goodine, could we -- staying with Exhibit N-37, could we call up PDF page 12, please? Line 5 is where I'm going.

BY MR. MAHODY:

[11:00:05] **Q.** Here Ms. Palmer in her report indicates:

> ...public utility commissions have also explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100 percent demand-related. For example:...

And there Ms. Palmer lists seven

citations and their detailed links provided to each of those public utility commission references.

Mr. Blair, are any of those seven references incorrect?

[11:00:42] **A.** (Blair) No, not that I'm aware of.

Q. And, Mr. Blair, do you agree that even a theoretical Minimum System has load carrying capacity and will necessarily serve a portion of customers' demand?

A. (Blair) Yes.

Q. And in some jurisdictions, Mr. Blair, such as Ontario, an adjustment is made to account for the peak load carrying capacity of the theoretical Minimum System?

A. (Blair) Yes, that's correct.

Q. Okay. And I'd like to show you another document. It's a recent decision from the Connecticut Public Utilities Commission.

MR. MAHODY: Mr. Goodine, I sent you a copy of the -- it's an October 2025 decision from the Public Utilities Regulation Authority in Connecticut, and if we could turn over to PDF page 200.

BY MR. MAHODY:

Q. And here in this decision you'll see a paragraph in the centre of the page "To arrive":

> To arrive at customer-related costs, the Company selected the minimum sized piece of equipment for each cost category and multiplied its embedded cost by the number of units in service. The residual demand-related costs were calculated as the difference between total plant costs in each category and the customer-related costs. The MSS [the minimum system study] approach is one of the two recommended methods in the NARUC Electric Utility Cost Allocation Manual. NARUC Manua, page 90. In its initial proposal, the Company did not attempt to quantify the minimum system's load carrying capacity, i.e., the delivery capacity of each category of equipment included in the MSS approach.

And further down into the next paragraph starting in the middle:

> The Authority [the Board] requested that the Company and the OCC submit alternative ACOSS

models that calculate a per-customer load-carrying capacity value and credit each customer class that value when allocating residual demand-related costs.

And just two other references, Mr. Blair, before I come to you. Over at page -- PDF page 202, in the middle paragraph the Commission indicated that the Minimum System approach is a shared -- is a just and reasonable approach to cost classification, but the Minimum System's load-carrying capacity should be considered when allocating residual demand costs.

Now, Mr. Blair, do you follow these matters? Were you aware of this decision from the Connecticut Public Utilities Commission?

A. (Blair) No, I wasn't aware of this decision.

MR. MAHODY: And maybe just before I keep going, Mr. Chair, if we could mark this as an exhibit.

THE CHAIR: It will be Exhibit N-44.

--- EXHIBIT NO. N-44:

October 2025 decision of the State of Connecticut Public Utilities Regulatory Authority

BY MR. MAHODY:

Q. Mr. Blair, what is the load carrying capacity of the Minimum System that Nova Scotia Power uses in this Application?

A. (Blair) There's no load-carrying capacity adjustment used by Nova Scotia Power.

Q. Okay. And just let me back up for a second. I do appreciate that there's no adjustment, but what is the capacity of the Minimum System method -- the system that Nova Scotia Power is proposing?

A. (Blair) If you look at footnote 10 of Ms. Palmer's evidence it actually comments on -- this information was requested from Nova Scotia Power and Nova Scotia Power indicated that they don't have the uncollected data to calculate this.

A. (Willett) And I would just note

as well, Ms. Palmer actually recognizes in her evidence that this would require -- I'll just use the words on page 14:

> Identifying the specific load carrying capacity of [Nova Scotia] Power's minimum system [study] is an exercise that would require thoughtful analysis from [Nova Scotia] Power and other stakeholders.

And just linking back to the Settlement Agreement, this is part of the reason why, you know, the company and stakeholders have recognized that this is a complex matter and recognize that having an application in 2026 to discuss this matter more thoroughly. And as noted in Ms. Palmer's evidence, she has recommended that -- you know, recognizes the Settlement Agreement herself. And, you know, that is part of the reason why this has been recognized as an item for -- to be discussed in future because it is a complex matter.

Q. So, Mr. Willett, do I understand that Nova Scotia Power's evidence is that there is a load carrying capacity of the Minimum System, but Nova Scotia Power has not yet calculated it?

A. (Willett) I would say it's an issue we haven't analyzed, we haven't calculated. As I just mentioned, it is a complex issue around the Minimum System Study, and that is the reason why we've discussed having an application in 2026, allowing the company to provide the full information on what its proposal would be in regards to the Minimum System Study in use beyond this test period.

Q. But you agree that your proposed Minimum System does have the load carrying capacity? It has some load carrying capacity; do you agree with that?

A. (Willett) Yes.

Q. The Consensus Agreement, Mr. Willett, makes reference to the application as you've talked about in 2026 for the consideration of future cost-of-service matters. What is it over the next two years that Nova Scotia Power is going to root out and seek out detail on to assist in determining whether or not the Minimum System classification is the appropriate system classification going forward?

A. (Willett) I think it would be seeking stakeholder feedback, continuing that discussion, and that would be an input into the Application that the company would need to file regarding that. So that would be the -- the starting point would be having stakeholder discussion around the Minimum System Study.

Q. But this isn't in any way analogous, say, to like when Nova Scotia Power would have a rate, some of its time-infused rates, that you put out a pilot rate, and you see was there going to be take up over a couple year period and see what that take up is. That isn't what this is, is it?

A. (Willett) No, I would not expect it to be that. What I would expect it to be is a continuation of the collaboration that the company has had with customer representatives and having discussions around the Minimum System Study and potential alternatives that we feel, and back to the basic principle of cost of service that appropriately reflects cost causation regarding the demand and energy component of the distribution system as -- sorry; I mean demand and customer.

MR. MAHODY: Mr. Goodine, at N-37, Ms. Palmer's report, could we turn to PDF page 20 at line 16?

THE CHAIR: And I'm not sure where you are in your questions, Mr. Mahody, but at a convenient point in time -- if you're getting close to the end, please continue, but if there's a -- you know, you're not, and there's a place to break, it would be appreciated.

[11:10:06] **MR. MAHODY:** I think with this one question then it would be an appropriate time to break.

THE CHAIR: Okay.

MR. MAHODY: I'm not far from being done in total either, but -- okay.

BY MR. MAHODY:

Q. So N-37, page 20 in the PDF, line 16. Here Ms. Palmer has identified additional Cost-of-Service Study methods that she thinks should be reviewed as part of whatever future process occurs, and she lists out the three areas here. Has Nova Scotia Power had a opportunity to consider those, and do you have a position on whether you agree with those being part of consideration in future cost-of-service matters?

A. (Williams) Thanks, Mr. Mahody. I think what the Settlement Agreement does is it expressly identifies Minimum System as being subject to what we would see as a standalone application or matter that we would bring to the Board in 2026, and that's what's described in the Settlement Agreement. And as it says in the Settlement Agreement, any party may take any position they so choose.

Subsequent to the test period, the '26-'27 test period, we would not -- our expectation is not that the Settlement Agreement or the positions that parties have taken in relation to the Settlement Agreement in any way binds them, and all cost-of-service issues would be before the Board for consideration at the next General Rate Application or the next standalone cost-of-service proceeding.

That said, I think there is an expectation -- I know there is an expectation from Nova Scotia Power, and I would think there's a similar expectation from all parties, that we're not redoing the same extensive cost-of-service process that we just undertook in relation to all cost-of-service matters in subsequent proceedings. I would expect that we do get some value out of what we just went through, but certainly the Minimum System is one that was identified as being for further consideration.

Q. Okay. And so back to Ms. Palmer's three additional methods that she is recommending you reviewed. Do you agree that the next point, Cost-of-Service Study -- a full Cost-of-Service Study is being undertaken, that those matters should be considered?

A. (Williams) I think the next time a full Cost-of-Service Study was undertaken all matters would be out there. But as I said, no-one's bound as a result of this process or the agreement, but certainly the expectation would be that we've reached common ground on certain aspects of these.

I think where my uncertainty in terms of the recommendation lies is when you read from line 9 it says:

> I recommend that the Board expressly state that not only should the [minimum system] methodology be subject to a future proceeding and determination...but that the same requirement should apply to several other [cost-of-service] methods...

And so if Ms. Palmer's intention there is to include these other methods in the 2026 filing that's described and expressly set out in the Settlement Agreement, we would disagree with that recommendation and we would not feel that that's the expectation of Nova Scotia Power. But if she's referring to future cost-of-service studies, then, as I said, I think all issues would be subject to the Board's consideration and assessment in that setting.

Q. Okay.

MR. MAHODY: Mr. Goodine, if we could just go to N-27, PDF page 11. It's the Consensus Agreement of the cost-of-service section that we were on earlier.

BY MR. MAHODY:

Q. And so Mr. Williams, given your comment that you just made, under Item AA:

> ...use of the Minimum System methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board, for which an application will be made in 2026...

It's your position that it will be an application dealing exclusively with the Minimum System method, is it?

A. (Williams) That's the expectation, yes.

Q. Okay.

A. (Williams) But that is an application to be filed in 2026. That is not to say that if a Cost-of-Service Study is filed subsequent to the test period that has relevance to any date subsequent to 2027, that it would be limited to Minimum System. That's not what I'm saying.

I don't know if I'm being clear, but I'm trying to be.

Q. Yeah, certainly the exclusive nature of the Minimum System method wasn't apparent to me reading the words, but I appreciate that I'm just reading the words.

MR. MAHODY: Okay, Mr. Chair, those are -- this would be an appropriate time to take a break.

THE CHAIR: Okay. So it's 11:15. We'll come back at 11:30.

Thanks.

--- Upon recessing at 11:15 a.m.

--- Upon resuming at 11:31 a.m.

CRAIG FLEMMING, Resumed:

BLAKE WILLIAMS, Resumed:

MICHAEL WILLET, Resumed:

ANDREW BLAIR, Resumed:

THE CHAIR: Okay, Mr. Mahody, I think we're good to resume.

MR. MAHODY: Thank you, Mr. Chair.

And Mr. Goodine, the same exhibit, just the next page is where I'd like to go. It's N-27, PDF page 12. And it's the PHP treatment section.

CROSS-EXAMINATION BY MR. MAHODY, (Cont'd)

Q. So under Item A, panel, it indicates:

> [Nova Scotia] Power's 2026/2027 cost of service study includes PHP as an above-the-line customer based on the forecast of receiving Board approvals for a new PHP tariff in time to implement for January 1,

2026.

Can I start with what Nova Scotia Power understood the Settlement Agreement as an early September document, as of that time, what were you anticipating in relation to that clause?

A. (Williams) I think just what it says, Mr. Mahody, and I think certainly the timing of it, so an early September document, and suggesting that it would be receiving Board approvals for a new PHP tariff in time to implement for January 1st, 2026, it was really meant to account for the potential for that, but I think everyone realistically understood that that would be a best-case scenario.

Q. Okay. And so this reference, Mr. Williams, is to a new previously non-existing PHP tariff?

A. (Williams) That's correct. So at the time, the renewal of the ELIADC would have been before the Board, and that's not in reference to this -- this is in reference to an above-the-line tariff, whereas the

ELIADC is a below-the-line tariff.

Q. Okay. And I am aware that on December 29th, 2025, Nova Scotia Power filed an Application; it's the M12661 matter. And it has the implementation date of the new rate of January 2027 for the new PHP rate. No later than, I guess, is your comment, then?

A. (Williams) Yeah, that's exactly what I was going to just clarify, and that's the reference that we spoke about with Ms. Rudderham earlier, yes.

Q. Okay. So just describe to me, Mr. Williams, what happened between September and this clause and then a filing in December indicating a potential of a year delay?

A. (Williams) I don't know that it's necessarily a potential year delay. I think what we were thinking with the phrasing in the Settlement Agreement was that, you know, ideally, it's in place January 1st. That's -- it's clean. The calendar year is applicable. But as I said, I think we all recognize that was a best-case scenario.

So that would be kind of one end of the timeline, if you were. The other end is a no later than is the January 1st, 2027. So I don't see it as a year delay so much as we're recognizing there's a window to work within because the IDC has been removed for the calendar year 2026.

Q. Okay. And I think I heard in your responses to Ms. Rudderham's questioning that you appreciate the clear difference between a tariff being available and service ever being taken under that tariff. Those are two different things, aren't they?

A. (Williams) Yes, I'd agree. And attempt -- the Settlement Agreement here attempts to account for that as well by reference to PHP's decision to take service under any new above-the-line tariff. But yes, I would certainly agree with the distinction you're drawing.

Q. And in Item B, there are three factors that are referenced, the -- PHP's firm load at 8 megawatts at the three coincident peaks, and then a couple of other factors. Can you confirm that all of those factors are the -- represented for determination in the M12661 December 29th Application?

A. (Williams) Yes, I can. Those are the assumptions that are referred to kind of throughout this section of PHP treatment. So the 8, the 65, and then the forecast usage as a result of the introduction of Goose Harbour.

Q. And so Nova Scotia Power is not looking for approval of those factors right now in this matter, they're looking for those to be dealt with in the December 29th filing?

A. (Williams) That's exactly -- so in terms of those three elements being contained within or addressed within the Tariff Application, that's correct. And this kind of goes back to the discussion you and I had earlier about filing the Settlement Agreement, and this was some of the back and forth we had. Do we put the Settlement Agreement in even though it deals with, you know, things outside this proceeding? Does it cause confusion? So we attempted to build into the Application the elements of the Settlement Agreement that are specific to this Application. But I recognize the discussion you and I had previously on this.

Q. Okay. But related to those assumptions regarding PHP is a reference to the potential of a deferral account?

MR. MAHODY: And if we could go to the next page, Mr. Goodine, please, under Item G?

BY MR. MAHODY:

Q. And here, the Consensus Agreement indicates:

> [Nova Scotia] Power may seek Board approval for a deferral account...for any [Nova Scotia] Power revenue variances that may arise in ['26] or ['27] from the following scenarios, which costs would be collected [or] refunded [to or from] above the line

customers...

And you go on to cite a number of factors.

So just so that I'm clear about what approval the company is seeking from the Board, are you seeking the establishment of such a deferral account? Or are you simply just indicating the ability to seek one at some future time?

A. (Williams) Yes, and so we're looking at the Settlement Agreement currently, which is not the Application. The Application does seek approval of this deferral. So to be clear, Nova Scotia Power is not seeking approval of the use of the number 8, or 65, or the assumptions that have gone into the tariff, but recognizing the materiality of PHP and import of PHP to the electricity system and the magnitude and materiality of any potential impacts from deviations from the assumptions that have been used, now that they're going above-the-line. The deferral account is something that we felt, and obviously others that have signed this as well, felt was a prudent measure to ensure that the full costs and the appropriate costs are being captured. And when I say costs, I mean the cost of providing service, not just to PHP, but to all. And certainly Bates White speaks to this in their evidence as well.

So we are looking -- to be clear, we are looking for approval of the deferral to acknowledge the materiality of PHP going above the line, and the potential implications, if there are any differences from the assumptions that have gone into putting them above the line as part of this Application. So that deferral would capture those.

To your previous point about are we asking for approval of the 8, the 65, and the timing of Goose Harbour, those assumptions, we're not asking for approval of those. Certainly some of those would be approved as part of the tariff filing, the new tariff above-the-line filing. But certainly some of those would

-- in relation to the timing to Goose Harbour, that would not be approved, necessarily, as part of the filing. It would be borne out as that project progresses and comes online. And so when I speak to that, obviously if Goose Harbour comes on earlier or later, it has a material impact on the cost recovery from PHP as an above-the-line customer because of the magnitude of load that Goose Harbour would be replacing. But again, those are issues that are not needing to be determined as part of this process, other than approval of the deferral itself that would address those in the future.

[11:40:08] **Q.** The cost of service on which the Application is based has those assumptions in it. To the degree to which the actual outcome may differ from those assumptions, you're looking for a deferral, so the company is kept whole by collecting from other customer classes?

A. (William) So the company or customers are kept whole, quite frankly. I think it's really recognizing that this is a new step in Nova Scotia.

PHP is a big customer; it's a significant customer. And taking them above the line, while beneficial for other customers, has the potential to have material deviations from the assumptions, and those material deviations could be significant for both customers and the company. And so the deferral was arrived at as a mechanism that would be an appropriate measure to mitigate that risk and address those deviations.

MR. MAHODY: Mr. Chair, I think I'm done, but if I could just have one moment?

(SHORT PAUSE)

MR. MAHODY: Thank you, Mr. Chair. Those are my questions.

THE CHAIR: Thank you, Mr. Mahody.

Mr. Murphy?

MEMBER MURPHY: Thanks, Rob.

QUESTIONS FROM MEMBER MURPHY

Q. Good morning, panel. I just want to start with a really quick question for Mr. Blair, I think, just following up on the discussion you had this morning with Mr. Mahody.

Just so I'm clear, under the Minimum System methodology, are costs related to service -- customer services and meters, are those classified as customer costs?

A. (Blair) Yes, those are customer costs. And really, the Minimum System methodology doesn't really consider those as part of it. Those are just separately assigned to customer.

Q. Okay. Perfect. Thank you. Okay. I just wanted to touch upon a few things. I don't think we need to call this up, but in Synapse's evidence, that's Exhibit N-37, PDF page 10, Ms. Palmer suggests that Nova Scotia Power included distribution lines that serve voltages up to 25,000 volts in the Minimum System Study.

And she went on to state that:

> ...it is unreasonable to suggest that the cause for installing primary equipment is the presence of a residential customer on the distribution system, regardless of that customer's demand, when residential customers likely receive service at a fraction of [that] primary voltage.

So a couple questions. First, I want to get confirmation that Nova Scotia Power did in fact include distribution lines that serve voltages up to 25,000 volts in its Minimum System Study?

A. (Blair) Yes.

Q. And my next question would be why?

A. (Blair) The Minimum System classifies all poles that are -- all poles and lines that are, say, secondary or primary, and the lines up to that voltage is included in the primary service level. So that's why they are included there. There are separate -- different types of equipment for -- like, there's Minimum System and -- minimum level and then higher voltage levels as well. So anything that's higher than a certain amount would be classified as demand.

Q. So even though a residential -- according to Ms. Palmer, even though a residential customer can rely on -- only needs, let's say secondary system voltage, doesn't need 25,000 volts to serve its own demand, it would still be included in the system -- Minimum System methodology?

A. (Willett) Synapse IR-6, Part C, that would be a good reference to the question:

> The Company [includes] only distribution lines defined at [Nova Scotia] Power as serving voltage at 25kV and below.

Q. I guess Mr. Blair answered that question, I think, that you did include up to 25,000 volts in that Minimum System Study, but if a residential customer doesn't need 25,000 volts to meet its demand, why would those necessarily be included in the Minimum System Study?

A. (Blair) So the thought behind the

Minimum System is that the cost that -- the distribution system is built out to reach every customer and to meet a certain level of demand. So even though it’s not really serving one customer, it’s still -- the reason the lines are built out, the reason there is more lines at cost, is to reach all the customers. And that’s why they’re considered customer related. So there is -- to the extent that it’s the disbursement of the system really what is considered customer-related, not necessarily it is serving one customer.

Q. Does the disbursement of the system require 25,000-volt service?

A. (Blair) Not necessarily.

Q. But yet it’s included in the cost associated with that primary system voltage that’s included in the Minimum System costs?

A. (Blair) Yes, that is what NS Power has determined is the least cost way of getting that power to that customer is at higher voltages in certain cases.

Q. Okay. Thank you.

Also in Synapse's evidence, on PDF page 16, again I don't think there's a need to call it up, but Ms. Palmer suggests that if the Board were to approve Nova Scotia Power's Minimum System Study, she recommended that Nova Scotia Power:

> ...credit each customer class with 1.5 kW per customer, applying the credit to the NCP demands used for determining minimum system...allocators.

So my question was going to be similar to what the Board asked for, or Mr. McGrath asked for in Undertaking U-5, if we could provide something similar to Undertaking U-5 but incorporates this recommendation, rather than assigning all the Minimum System cost to 100 percent demand?

(SHORT PAUSE)

MR. WILLETT: Sorry for the delay. We were just discussing as these types of analysis require us to do a full rerun of the cost of service and go through a lot of process and it's the same people doing these type of analysis, so we're just cautious of the timeline related to doing this undertaking, and given the Settlement Agreement, and the fact that there would be a 2026 application, thought might be that that might be more appropriate as part of that proceeding, but if it is something required under this proceeding, we would be willing to do that.

BY MEMBER MURPHY:

[11:50:06] **Q.** I'd like to get it.

A. (Willett) Okay. Yeah.

MEMBER MURPHY: So Mr. Chair, that would be, I guess, Undertaking U-6, if you want me to repeat it.

THE CHAIR: Yeah.

MEMBER MURPHY: I guess, in effect, it's what we asked for in Undertaking U-5, but instead of assigning all the Minimum System's Study cost to

100 percent demand that NSP credit each customer class with 1.5 kilowatts per customer, applying the credit to the NCP demands used for determining the Minimum System demand allocators, as suggested by Ms. Palmer in her evidence.

THE CHAIR: That's Undertaking U-6.

UNDERTAKING U-6 - To take cost changes from NSEB IR-128 and NSP credit each customer class with 1.5 kilowatts per customer, applying the credit to the NCP demands used for determining the Minimum System demand allocators

BY MEMBER MURPHY:

Q. Mr. Blair, in your report, Exhibit N-9, PDF page 17, or 1707, there's discussion about the DDA and how the costs associated with a DDA would be classified. And when I read it, it suggests to me that Nova Scotia Power's intent is to classify the costs associated with the DDA to the weighted average of Nova Scotia Power's rate base and allocate those classified costs by a weighted average of the allocation of rate base. Is that correct?

A. (Blair) Yes, that's correct.

Q. Do you have a sense -- I don't think I'll ask for an undertaking, but do you have a general sense instead of doing an allocation on those grounds if you allocated the costs of the DDA solely to generation, what that might have -- what impact that might have on rates?

A. (Willett) So the DDA, there’s no impact of the DDA in this test period, and when going through the cost-of-service process, this was prior to securitization being essentially the path forward that is expected by the company, so the amount that's going into the DDA is expected to be much smaller due to securitization. And as the company has noted, a securitization rider would be applied once securitization takes place, and in that application, the company would be proposing to do securitization based on either the DDA approach or by generation. So that's something that the company is considering right now.

Q. So that would come forward with the securitization rider?

A. (Willett) That's correct.

Q. Okay, thank you. I just wanted to talk about the DSM rider for a second as well. Currently, as I understand it, and you correct me if I'm wrong, perhaps Mr. Willett, the DSM rider is allocated as 75 percent to the cost of programs undertaken for rate class, with the remaining 75 percent allocated to system benefits. Is that correct?

A. (Willett) The remaining 25 percent; correct.

Q. Twenty-five (25) percent; sorry.

A. (Willett) Yes.

Q. Yeah. And under the proposed

cost of service, Nova Scotia Power is proposing to remove the allocation system benefit so that 100 percent of DSM costs would be allocated to classes in accordance to program spending. Is that correct?

A. (Willett) That's correct.

Q. Okay. And there was a reference in some of the evidence about a response. There was some discussion, I guess, through this process, of how to determine the allocation of DSMs, and there was an analysis done by Nova Scotia Power that was referred to in CADR 87, I believe it was, where basically the analysis concluded that there is no system benefit to DSM and thus the reason for assigning 100 percent of those costs to -- as proposed in the GRA.

So I went back and I reviewed that analysis. I don't really understand how that analysis shows that there's no system benefit. So I'm just wondering if you can help me out here and describe why that analysis or how that analysis shows that there’s, in fact, no system benefits associated with DSM.

A. (Willett) Yeah, I would just mention I don't believe the analysis showed there was no system benefit. The analysis showed that there was a much smaller degree of system benefit than the 25 percent. If my memory serves me correct, it was somewhere between 5 and 10 percent, maybe 7 percent, or something to that effect. So it had showed that there was a very small amount of system benefit based on that analysis.

Q. So I guess, my question, though, was really I -- whether it's 5 percent or 10 percent I'm not so much concerned about that. I'm trying to understand how that analysis, is my -- I couldn't understand how it shows that there's that limited amount of system benefit.

(SHORT PAUSE)

MR. WILLETT: I was just checking on the panel. So I didn't calculate that analysis and my colleague wasn't part of calculating that, but my understanding was that there was a number of, essentially, models run with simulations in order to look at what the benefit to different classes would be based on investments in only singular classes to produce that result. But I can't speak to the details of that analysis.

BY MEMBER MURPHY:

Q. Okay. I just wanted to go back to the Minimum System method just for a second. This is what I've inferred from reading the evidence as it relates to the Minimum System method and the Basic Customer method, and I will -- I'm going to ask you if you agree with me if this is -- if my -- if what I've inferred from the evidence is correct.

In the context of a rate setting regulatory proceeding, it seems to me that the Basic Customer method would generally establish the minimum possible customer charge for distribution costs, while the -- sorry; did I say the Minimum System method, or did I say the Basic Customer method? Sorry; I got it backwards.

Seems to me that the Basic Customer method would generally establish the minimum possible customer charge, while the Minimum System method would generally establish the maximum possible charge. Would you agree with that?

A. (Blair) I believe the Basic Customer method would result in the lowest customer-related costs being allocated to rate class, and Minimum System method would have a -- sort of the highest customer-related costs being allocated to rate class. But I do want to make the distinction, with rate design there are differences between what is classified as customer related and what is actually in the customer charge.

Q. I understand that. Okay.

A. (Willett) Yeah, and I would just add as well, so the Basic Customer method, it doesn't -- it would only treat certain items as 100 percent demand, where the Minimum System method would recognize that there is both customer- and demand-driven costs related to certain assets.

[11:59:59] **Q.** Is there a -- I know it was referenced in Elenchus's evidence, as well as perhaps Ms. Palmer's evidence, there is reference to I think the Zero Intercept method. Is that kind of a hybrid sort of methodology that would sort of fall between the Minimum System method and the Basic Customer method?

A. (Blair) It’s really more like the Minimum System method, but instead of it being a Minimum System that has some delivery capacity it’s a hypothetical system that reaches every customers but doesn’t have any delivery capability at all.

Q. Okay. And are those really the three basic methods that are primarily used in cost-of-service studies?

A. (Blair) Yes, that’s right. And there’s often multiple ones considered and then some kind of judgmental percentage applied to them is necessarily the results of each one.

Q. Okay. Thank you.

A. (Willett) And just on the methods used, Elenchus has also provided a jurisdictional scan which would show that across Canada it's typically the Minimum System or the Zero Intercept method, or it is based off of one of those type of studies that is employed across Canada. The Basic Customer method is not used -- and I'll let my colleague speak to this, but I'm not aware of where the Basic Customer method is used in Canada.

A. (Blair) No, not specifically the Basic Customer method, but there are examples where jurisdiction does not classify certain distribution costs between customer and demand the way Nova Scotia Power and others do.

Q. Do you know what's primarily used in the United States?

A. (Blair) I couldn't say overall what's primarily used in the United States.

Q. Okay. This is my last couple questions, and it's really related to this Consensus

Agreement. On PDF page 11 of N-27 -- again no need to call it up, Jeff, I don't think -- it states:

> ...the appropriate apportionment of assessment costs from the Maritime Link is between generation and transmission will remain open to be addressed as Parties see fit in any proceeding to determine rates after...2026-27...

I'm just curious, how are Maritime Link assessment costs currently apportioned between generation and transmission?

A. (Willett) So this item was discussed back in, I believe it was the 2019 or maybe it was a little bit before that, but a fuel stability plan in the cost of service or strawman's presented, and the company has been using SLF as the methodology system load factor in order to classify between energy and demand for that. When there's -- just a second. So that is for the base, the Nova Scotia Block and Supplemental Block, but then any surplus would be just 100 percent energy.

Q. I guess my question wasn't really how it was assigned to energy or demand, it was generation and transmission.

A. (Willett) Yeah, and it's all generation.

Q. Okay. Thank you.

And then lastly ---

A. (Willett) And, sorry, I just want to clarify as well, but there are assets within Nova Scotia not related to the Maritime Link assessment costs but the Maritime Link assets, transmission assets, that would be 100 percent transmission assets as well.

Q. Okay. Lastly, in the Consensus Agreement on PDF page 14 it says, "Within a reasonable amount of time following the execution of this Settlement Agreement..."

Which I believe was August 29th of 2025.

> ...[Nova Scotia] Power will provide...confirmation that radial to generation lines being allocated to the generation function do not also serve any load; and (b) the methodology that [Nova

Scotia] Power is proposing to functionalize storage assets.

Is that -- do you have any update on that?

A. (Willett) Not at this time. So once we get through this process that would be an item that we'd be looking into.

Q. Okay. In terms of looking into it, though, based on what I heard this morning through your discussion with Mr. Mahody, that wouldn't be incorporated into the upcoming application related to Minimum System Study.

A. (Williams) That's correct, Mr. Murphy. It wouldn't be an issue that would be raised in that filing where we'd be seeking a determination on it. It's just recognizing an information flow between participants and the agreement.

Q. Okay. Thank you.

MEMBER MURPHY: Those are all my questions, Mr. Chair.

MEMBER DEVEAU: I have no questions, Mr. Chair.

QUESTIONS FROM THE CHAIR

Q. I don't think I have much left so this might be a bit spotty coming at you, and I apologize for that.

THE CHAIR: I'm going to start with, Mr. Goodine, if we could pull up Exhibit N-17 and go to PDF page 111. And if you're able to just make that a little bit bigger so it's easier to read.

BY THE CHAIR:

Q. So, Mr. Willett, just a couple of kind of high-level questions first that may be for you, although if they're not you can pass them on.

Just in terms of residential customers, looking at this particular table my sort of takeaway from the first column is residential customers are about or account for about half of Nova Scotia Power's sales in 2026.

A. (Willett) So under the cost of service column you can see they would have approximately

$1.1 billion of the $1.8 billion costs related to FAM customers.

Q. Okay. I was going to come to that. But just in terms of the column before that, sales in gigawatt hours.

A. (Willett) Sales. Yeah, sorry, I apologize.

Q. My lawyer math on that one is about -- Mr. Williams is just smiling about lawyer math, is about 50 percent.

A. (Willett) Correct.

Q. And in terms of the cost column that you just looked at on a cost basis under the cost of service model, residential customers are responsible for about 60 percent of the costs.

A. (Willett) Correct.

Q. And, Mr. Blair, you wouldn't necessarily expect those two numbers to be the same because not everything is allocated on an energy basis.

Is that fair?

A. (Blair) Yes, that's fair.

Q. And, Mr. Blair, do you agree that the cost of service allocation it's not a pure science?

A. (Blair) That's right. It's often said it's more of an art than a science.

Q. Yeah, there's a lot of subjectivity, generalization, averaging, simplification that's involved in the processes?

A. (Blair) Yes, there's a lot of judgment that goes into what the methodology should be and then it sort of turns into a science from there. But, yeah, at the first stage there's a lot of judgment.

Q. And would you agree that as a result many regulators often recognize sort of a range of reasonableness as the outcome of cost allocations, so in this particular jurisdiction so the 95 percent to 105 as opposed to trying to precisely target 100 percent allocation under a particular method to each rate class?

A. (Blair) Yes. I believe a range of reasonableness is used in every jurisdiction in Canada for electricity.

Q. And in this particular model the end result is showing for the residential class a 97.18 percent under a revenue-to-cost ratio. That's -- I'm interpreting the table correctly?

[12:10:10] **A.** (Blair) That's correct.

Q. Yeah. And so consistent with what you just said, we wouldn't necessarily think of that as being subsidized by other rate classes. It's within that range of reasonableness and, you know, within the range of that's appropriate costs that are allocated to that particular class?

A. (Blair) Yes, that's right.

Q. And Mr. Willett, just referencing back to the Undertaking, U-5, that was asked and Mr. Murphy's follow-up, that stepwise methodology, in terms of getting from the costs of service that are allocated in

Column 2 to the RC ratios at the end, that is set out in the middle box there that we see, “Steps and assignment of revenue responsibilities”?

A. (Willett) That’s correct. If -- maybe it would be helpful to walk through some of the ---

Q. Sure, go ahead.

A. (Willett) --- items?

So if we look at the heading “2026 sales at 2025 base cost rates,” what that shows is if we had 2025 rates how much revenues we would collect from the different classes, and that is showing the domestic class would be at the 0.9. And so what we do in the various steps is we apply a uniform increase across all classes in order to collect the shortfall in revenue, and the shortfall in revenue is the $166 million that you see at the bottom.

But the result of that is that many of the classes are outside of that 95 to 105 band, so each step in the process is getting those customers to within that 95 to 105 band.

Q. And the process that you've set out here is, as I understand it, the same as you've used in the past several General Rate Applications except for you've got a step where PHP is directly assigned at 105 percent?

A. (Willett) That's correct.

THE CHAIR: Mr. Goodine, if we could now go to -- I'm going to come back to this exhibit, I think, though, but if we could go to Exhibit N-27, PDF page 537. It should be NSEB IR-127.

BY THE CHAIR:

Q. And just looking at the table, and again, Mr. Willett, this may be for you, but my understanding was that -- or my interpretation of this, just to confirm that it's correct, again for the domestic class, as a result of all of the changes that have been made to the Cost-of-Service Study from what was the case in the last General Rate Application, the result is a shift in costs under the new method of $26 million to domestic customers?

A. (Willett) That is correct. That's the impact of the old cost-of-service methodology compared to the new cost-of-service methodology or the proposed cost-of-service methodology for the 2026 test year.

Q. And we can see quickly from that table that the residential or the domestic class is the most negatively impacted class as a result of that change? In fact, almost all other rate classes benefit?

A. (Willett) That's correct.

Q. Mr. Mahody and Mr. Murphy had asked a number of questions about the Basic Customer method and Ms. Palmer's recommendations around that. And my recollection from the tables that were pulled up when Mr. Mahody was asking questions was that if one were to adopt the Basic Customer method for allocating those costs that the results in 2026 would be to shift about $29.1

million, thereabouts, back to the domestic class and in 2027 it was around 30 million?

A. (Willett) Subject to check, that sounds reasonable.

Q. Well, maybe we can go to that.

__THE CHAIR:__ So it was an Excel file, Mr. Goodine. It was -- I think it was N-27(iii), and it was relating to IR-128.

__MR. WILLETT:__ Yes, I see the 29.8 million.

__BY THE CHAIR:__

Q. Okay. I said .1, so it's 29.8.

So it would appear that this particular issue, which was left on the table for resolution in another day, would completely offset all of the changes that were -- you are proposing to make for the domestic class. Is that correct?

A. (Willett) From a cost-of-service perspective, agreed. But as discussed with Mr. Mahody earlier, there are other factors that are driving the increase to the domestic class being above average, outside of the cost of service as well.

Q. Right. But from a cost-of-service perspective, we looked at the difference in the cost-of-service model was the 26 million and making this one change would go the other direction, 29 or 30 million dollars, in both those years, so it would completely offset all of the other cost-of-service model changes.

A. (Willett) I would agree with that, but one thing I would also just highlight is the principles behind the cost-of-service proceeding was determining cost causation and looking at cost causation.

So moving away from the Minimum System method and going to the Basic Customer method would view that there are no costs driven by customer related to parts of the distribution system and, in our view, wouldn’t be in alignment with cost causation.

Q. Not in Ms. Palmer’s, though.

A. (Willett) Agreed. There's different opinions on the study. Agreed.

Q. That's right. Experts have different views on this particular subject.

A. (Willett) Correct.

Q. And, again, this particular issue, would have fully offset all of the other costs for the domestic class, was kicked down the road to not be resolved in this proceeding. Does that make sense, to implement all the other changes in the cost-of-service model and to leave this one that would have benefited -- potentially benefited the most negatively impacted rate class on the table?

A. (Williams) I think maybe just to address one of the things you'd said there, sir, is kicked down the road not to be addressed as part of this proceeding. The expectation is that it would be addressed for the purposes of this proceeding, so that Minimum System -- the issue of Minimum System or base customer would be finalized for the test period ’27-28 -- or ’26-27. Sorry. But that there would be a subsequent application that would determine the issue outside or after, subsequent to this, this test period.

In terms of whether it makes sense, I think what you have to do is look at the totality of it, the Settlement Agreement. And so I understand your point in isolation, speaking to this issue, and that goes to some of the things that were discussed in our Opening Statement where there’s a number of aspects to the Settlement Agreement, a number of aspects to any General Rate Application that need to be balanced. And when you have an interest-based solution like we were able to obtain here, or resolution like we were able to obtain here, it’s different than at a hearing like this where you’re able to look at each issue in isolation and determine what’s the best outcome from the Board’s perspective.

Here, there’s trade-offs that are able

to occur as part of those settlement discussions, and so whether it makes sense is a matter of perspective and I think needs to be considered as part of the total package of issues that were resolved with the consensus or Settlement Agreement.

[12:20:05] **Q.** Okay. The Board is not bound by the Settlement Agreement.

A. (Williams) Yes. As I confirmed with Mr. Mahody, that's certainly understood, sir.

Q. Right. And so from the Board's perspective, at the end of the day, it has to make a decision that produces just and reasonable rates, regardless of the Settlement Agreement; correct?

A. (Willett) I would agree, yes.

Q. Yeah, and the existence of the Settlement Agreement is certainly a factor to consider, there's no doubt, but in terms of why it would be reasonable for the Board to not take a hard look at what Ms. Palmer is suggesting, is your response simply that because that's what the parties agreed to in the Settlement Agreement?

A. (Willett) No, I think it's fair, and it's our expectation, I think that's why we're here today, that the Board would take a hard look at it and consider it, absolutely. The questions that are being asked are good questions and they're reasonable questions, and they're questions that the parties anticipated. And that's one of the reasons that the Minimum System Study was a carve-out to the Settlement Agreement for the determination. I think all I'm suggesting to the Board is that, you know, what is just and reasonable in this instance has been considered by the parties that were signatories for their own purposes. And again, I don't want to speak for parties, but I think the Settlement Agreement speaks for itself, in that the trade-offs that were made in perhaps other areas of the Settlement Agreement were sufficient enough for those parties to believe that moving forward with, in this instance we're discussing the Minimum System Study, was just and reasonable, or is just and reasonable, provided that there is the process to consider it and make a more definitive determination of it in the future.

So that's all I'm looking to convey. Certainly not suggesting that the Board is bound by the Settlement Agreement, but I would suggest that it's a compelling and weighty piece of evidence that's before the Board.

Q. One of Bonbright's principles, which is aimed at rate stability and predictability with a minimum of unexpected changes seriously adverse to ratepayers, moving forward with changes to your cost of service model that are having significantly negative impact on domestic class customers and proposing to address one that could have a significant -- could provide a significant offsetting benefit to those same customers for resolution only a few months later from now, but which won't be able to be implemented in rates for another couple of years, how is that consistent with Bonbright's principle?

A. (Williams) It's a great question, sir, and it's one that we've thought a fair bit about. And I think what we've used -- so when you talk about those types of impacts on customers, those are obviously very central to the discussion. And there are a number of things, and I listed some of them in the Opening Statement, that we've done to address those types of impacts. There's a number of others, too; I'm happy to discuss them. But I think when we talk about cost of service, we don't view cost of service as a mitigating factor for rate impacts. There's other mechanisms that are available for that. And as Mr. Willett indicated earlier, we approached this, just as everyone that participated in the process approached the cost of service from a principle basis, not looking for necessarily an outcome, and so it was about determining what is the most reasonable approach to address or identify the cost causation. And so that's where we were driving towards, and that's what we arrived at, and that's what we've moved forward with.

We certainly understand that changes like that have impacts to certain customer groups. And when you look at the table that we just looked at, and you look at the RC ratios, you would see that the domestic class is closer to the 95. All other classes are closer to the 105, PHP being at 105.

And I certainly recognize your point, I believe, with the line of questioning, that, you know, being closer to 95 is not indication that you're being subsidized by other rate classes, the 105/95 ratio recognizes, I think what you were talking about with Mr. Blair, the imprecision or the art of cost of service and rate design. And that's certainly recognized.

When you look at the math though, the reality is that any customer that's below a ratio of one is not, by definition, paying their cost of service. But

I think the 105/95 ratio recognizes, again, that imprecision and recognizes that being within that range can still be just and reasonable.

I raise that because, you know, we recognize the point you're raising about the impacts of the cost of service on the domestic class, and that's one of the reasons we settled on cost of service ratios with the domestic class being closer to the 95, with all other classes being closer to 105, to try to lessen that impact as much as we could, with one of the elements that is available to us, which is kind of the toggling of that RC ratio. So that's where some of the subjective aspects exist coming into play.

Q. So I guess my concern wasn't so much that this particular proposal by Ms. Palmer should be implemented to mitigate costs for a particular class. My concern was more -- I'm not sure what the outcome of that issue may be. The Board may agree that the Minimum System method, which has been used for a long time in this jurisdiction, continues to be the appropriate one to use. That's not the point I was trying to make. My point -- the point I was trying to make is it's an open issue. It's been an open issue since at least before the last General Rate Application. It potentially has a significant impact, which could potentially benefit the most negatively impacted rate class, and yet that was carved out to not be decided along with the package of the rest of those changes. That's the concern that I have.

A. (Williams) Yeah, and I go back to my point, I guess, which is that it was intended to be decided for purposes of this Rate Application, but ---

Q. Not finally. Not finally. You're intending to come back with an application in this year, 2026, to finally resolve that particular issue, aren't you?

A. (Williams) Not that it would impact rates in '26/'27.

Q. That's the point. Not that it

would impact rates when you're making a whole bunch of other changes that are impacting rates.

A. (Williams) Yes, and I think it's recognizing that impact. So I think again, you go back to the trade-offs, so I think it's recognizing the impact that the Minimum System has, it recognizes the views that parties have, and it's reflecting the desire of the parties that were signatories to have that more definitively assessed outside of this. But as I said, the agreement was to have the issue finalized within the test period.

Q. And if the Board decides that it's appropriate to not leave that loose thread and to resolve it as part of the same package where other changes are being made, that's open to the Board to do that in this proceeding?

A. (Williams) Certainly.

Q. And what impact does that have on the Settlement Agreement?

A. (Williams) I don't know that I'm the only person to provide a response to that, sir. It certainly would have, as we've just run through, a material impact on the terms of what was agreed to by the parties.

Q. Right. So you are the Applicant in this proceeding, and so I guess if the Board ultimately decides that, no, this issue needs to be addressed, should it address it based on the evidence that's filed in the proceeding, or should it just reject the Application and require you to come back? That's what I'm asking.

A. (Williams) No, I think a determination on the Application should be made.

Q. Okay. Mr. Blair, you had -- or Elenchus, in its report, had indicated it was not aware of any utility in Canada that uses the Basic Customer method to allocate distribution costs?

A. (Blair) That's right.

Q. And I think you acknowledged

earlier that there are many American utilities that do?

A. (Blair) There are.

THE CHAIR: Mr. Goodine, could we pull up Exhibit N-9, please? And I'm looking at page -- PDF page 1471.

BY THE CHAIR:

[12:30:12] **Q.** This is a jurisdictional scan that I think Mr. Willett may have mentioned previously this morning relating to this issue about who uses what method in Canada to allocate distribution costs. And if I understood -- if I understood Mr. Willett's comment earlier, his takeaway from this table was that most jurisdictions in Canada either use the Minimum System approach or some sort of -- use it as some sort of leaping-off point for making a judgment decision?

Is that -- I guess I can ask Mr. Willett. Is that a fair kind of restatement of what you said earlier?

A. (Willett) Yeah, I would say that

most, based on my understanding, but I would turn to Mr. Blair, as he's closer to what's being done in other jurisdictions, use a form of Minimum System, Zero Intercept, or use that as a basis for their allocation.

Q. So my looking at this table, I think there are eight jurisdictions there other than Nova Scotia. And for both primary and secondary distribution systems, it looks like three use the Minimum System, Saskatchewan, Quebec, and Newfoundland?

A. (Blair) They would use the results of a Minimum System methodology. And additionally, Ontario and New Brunswick have sort of set round numbers they use as the classification factors that are based on previous Minimum System studies.

Q. Right. But they don't follow the Minimum System precisely?

A. (Blair) That's correct.

Q. And in terms of the judgmental allocation, the British Columbia model, they're allocating

100 percent demand to the primary systems. It would be fair to say that that is more closely aligned with the Basic Customer method than the Minimum System method?

A. (Blair) Yes, for the primary.

Q. And for the Manitoba Hydro system, both primary and secondary systems would basically be following the Basic Customer method?

A. (Blair) Yes, that's correct.

Q. Mr. Blair, you're familiar with the United States National Association of Regulatory Utilities Commissioners, NARUC?

A. (Blair) Yes, yes.

__THE CHAIR:__ Mr. Goodine, I had sent you a document. The file was called NARUC COS.

__BY THE CHAIR:__

Q. This is taken from the NARUC website. Are you familiar with the NARUC Desk Reference Manual?

A. (Blair) No, not this specific

document.

Q. Okay. You haven't seen that one before.

__THE CHAIR:__ Maybe if I just can take you to -- just go to the next page, Mr. Goodine. Stop there, yeah.

__BY THE CHAIR:__

Q. There's a section here that has a basic description of cost allocation and revenue requirement that's highlighted. I don't have a particular question to that, other than to note that there's a footnote reference there to footnote 33 that I was going to go to.

But if you want to take a quick scan at the language there to see if you generally agree with that, that sort of high-level overview?

A. (Blair) Yes, I agree with it.

__THE CHAIR:__ Mr. Goodine, I'm not sure which page it's on, but it should be the next highlighted item for footnote 33. It's not at the end.

There we go.

BY THE CHAIR:

Q. The reference that they're pointing to in this particular case doesn't appear to be their own manual, but it appears to be "Electric Cost Allocation for a New Era," a manual by Jim Lazar, Paul Chernick, and William Marcis, the Regulatory Assistance Project, in January 2020.

Are you familiar with that?

A. (Blair) Yes, I am.

THE CHAIR: And -- that's good. Thank you, Mr. Goodine.

BY THE CHAIR:

Q. You're aware, then, that this publication suggests that the Minimum System analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution system that is customer related?

A. (Blair) I'm aware that it says that, yes.

Q. Yeah. You don't agree with that.

A. (Blair) I don't agree.

Q. Okay. And it also says that the Basic Customer method for classification is by far the most equitable solution for the vast majority of the utilities. You're aware it says that as well?

A. (Blair) Yes.

Q. And again, you don't agree with that?

A. (Blair) That's correct.

Q. And can you say why you don't agree with that?

A. (Blair) One of the -- this report, it's -- and behind it -- the group behind it, it's a bit more of an advocacy report than for the proper allocation. They're, in many ways, sort of moving costs towards energy related rather than demand related sort of to -- and I think it explicitly says so -- promote conservation to make the cost of energy, cost of electricity, each kilowatt hour, more expensive to promote lower use of energy. So it's not 100 percent economic based.

And the Minimum System, I think Ms. Palmer's report goes -- or submission goes through a few reasons why she disagrees with the Minimum System method and a few examples of why -- like, certain circumstances where why would this cost be allocated to customers, but in each circumstance, I think, well, why should it be classified as demand instead.

So for example, if a housing development has 10 houses 0.1 miles away or 10 miles away, it's still the same number of customers. Why would it be customer related? At the same time, why would it be demand related?

And I think it's a conceptual difference of the costs might not necessarily be causing

-- one incremental customer doesn't cause incremental costs, but in general a number of customers do. There is a cost to reach every customer and the cost of building out the system to reach customers, if customers are further away, is that customer related or is it demand related? And I'd say it's more customer related than demand related even though, in both circumstances, additional customer or additional demand isn't the cause of the costs.

So there are some circumstances in cost allocation where there are costs that's not exactly caused by one of the three usual allocators of customer energy and demand, but in these circumstances the customer still remains, in my opinion, the closest allocator to use, the closest cost driver.

Q. Is it fair to say that if not the most controversial, it's certainly one of the most controversial issues in cost allocation in utility rate-making?

A. (Blair) I think it's fair to say it's one of the most controversial.

Q. And it's been that way forever? Bonbright talked about how controversial it was in his seminal text?

A. (Blair) Yes, that's right.

Q. I had some questions about the capping of customer charges. I think that might be more a Panel 4 question than this panel?

It wasn't about allocating to the customer charge.

A. (Blair) So sir, it's the same people wearing a different hat, so if you've got the questions top of mind and you want to ask them now, I think we're fine to take them.

Q. I think I have them on another list, so I just was ---

A. (Blair) We can wait.

Q. --- before I left the panel, I

just want to make sure I wasn't losing my opportunity.

A. (Blair) You're not losing your opportunity.

[12:39:52] **Q.** Okay. In terms of the customer charge, though, if we do potentially consider adopting the Basic Customer method as Ms. Palmer talks about in her evidence, am I understanding the domestic customer rate design correctly and perhaps the small general as well that that would have an impact in particular on the customer charge and driving that lower?

A. (Willett) So it depends to what magnitude. So as noted in the evidence, the customer charge hasn't been set at the level of the cost of service for customer, it's been set at a lower amount. So it could impact it if enough customer ---

Q. Right, okay.

A. (Willett) --- costs were to be removed that it essentially no longer supported that customer charge.

Q. Okay. So it would certainly reduce the amount of costs that would go into the customer charge, but whether it's enough to fully make up for the fact that it's only set at 75 percent or something now is the issue?

A. (Willett) Yeah, I wouldn't say it's set at 75. That was the last agreement, and then we've increased from that, but ---

Q. Okay.

A. (Willett) --- you've got it.

Q. Okay. And the last question I have relates to the deferral for PHP. There were a few questions around that earlier. I think I understand what's going on in the request for the deferral being presented in this particular Application. I understood the request for the deferral would be for differences from costs based on whatever rate PHP is on, compared to what rate was assumed in the cost-of-service methodology, and that the deferral would adjust for any differences; is that correct?

A. (Williams) Yes, I think that's correct. I would just add that we also have the uncertainty that's created by Goose Harbour ---

Q. Yeah.

A. (Williams) --- and the advent of it coming online. So we would expect the deferral to address that as well, because it has the potential to be a very significant impact on load.

Q. In terms of the timing of the deferral, I think I did see a reference somewhere that the deferral was supposed to start January 1st, 2026. But I take it that really wouldn't start until whenever new rates are set?

A. (Williams) Yes, correct. There would be no -- nothing would be captured. Even if the deferral did start January 1, there would be nothing to be captured until new rates are set.

Q. Okay.

THE CHAIR: Those are my questions. I'll just go back around to see if there's anything arising from Board Panel questions.

Starting with Consumer Advocate?

MR. MURPHY: Nothing arising. Thank you.

THE CHAIR: Small Business Advocate?

MS. MacADAM: Nothing. Thank you.

THE CHAIR: Affordable Energy Coalition?

MR. DUKE: Nothing. Thank you.

THE CHAIR: Industrial Group?

MS. RUBIN: One brief question, please.

FURTHER CROSS-EXAMINATION BY MS. RUBIN

Q. I believe this is for Mr. Willett. Mr. Murphy was asking about a provision in the Settlement Agreement with respect to reviewing the cost allocation of the Maritime Link, and there was a discussion about how it’s treated -- how it’s functionalized. And currently you indicated it was functionalized, all of the Maritime Link -- sorry; everything in relation to the Maritime Link was functionalized as generation, with the exception of certain transmission assets; correct?

A. (Willett) The Maritime Link assessment fees would all be generation, and then what I had mentioned is there are transmission investments that the company has made related to that that would be in the transmission bucket.

Q. Right. And the issue being addressed by leaving this issue open is that there was discussions that the Maritime Link should be treated as two conjoined resources for functionalization purposes, whereby one provides the Nova Scotia Block, which is a resource like hydro functionalizes generation and classified the system load factor, and the other provides the opportunity to import the market-based power, which is a resource more like transmission, so functionalized transmission and classified to demand. And that's the issue that that caveat in the Settlement Agreement was intended to address; correct?

A. (Willett) I would say that's a fair summary of the discussions, correct.

Q. Okay. And that issue will be reviewed at a future time?

A. (Willett) That's my understanding, yes.

MS. RUBIN: Thank you.

THE CHAIR: Municipal Electric Utilities?

MR MacDUFF: No questions, Mr. Chair.

THE CHAIR: Department of Energy?

MR. BOYLE: Nothing.

Thank you, Mr. Chair.

THE CHAIR: Liberal Caucus...?

NDP Caucus...?

Port Hawkesbury Paper?

MR. MacDOUGALL: No questions, Mr. Chair.

THE CHAIR: Renewall?

MR. ROSCOE: No questions, Mr. Chair.

THE CHAIR: Did I miss anyone -- Mr. Mahody?

MR. MAHODY: And I have no questions.

Thank you, Mr. Chair.

THE CHAIR: Okay. Did I miss anyone before going back to Nova Scotia Power?

Okay. Then Mr. Clarke, any follow-up or anything by way of re-direct?

MR. CLARKE: No questions, Mr. Chair.

THE CHAIR: Thank you.

So, panel number one, and I think in record speed for a General Rate Application, so I appreciate your appearance and your testimony, and we'll see many of you again this afternoon and the days to come.

Mr. Blair, I guess this is your last appearance. Thank you for your evidence and appearing before us here in Nova Scotia.

Quarter to 1:00 now. I think probably makes sense to take our lunch break before we start in with the new panel. So we'll come back at, let's say, 10 to 2:00 and resume with the next Nova Scotia Power panel.

--- Upon recessing at 12:46 p.m.

--- Upon resuming at 1:57 p.m.

THE CHAIR: Okay. Welcome back.

Just before the lunchbreak I see some of those CVs came in. Thank you very much, Mr. Clarke.

MR. WIEDMAYER: Can you hear me?

THE CHAIR: Yes. Mr. Wiedmayer?

Hello, Mr. Wiedmayer. He may still be having issues there.

Anyway, as I was saying, the exhibits have been marked N-45, N-46 and N-47.

--- EXHIBIT NO. N-45:

CV of Andrew Blair of Elenchus Research Associates

--- EXHIBIT NO. N-46:

CV of James Coyne of Concentric Energy Advisors

--- EXHIBIT NO. N-47:

CV of John Wiedmayer of Gannett Fleming

THE CHAIR: And we'll see what we can do to sort out issues with the witness.

(SHORT PAUSE)

THE CHAIR: Mr. Clarke?

MR. CLARKE: Mr. Chair, what I would propose is you swear everyone on the panel, but I would only do introductions of the new members who haven't had introductions already. That seems like it would be the most efficient way to handle things, if that's okay with you.

THE CHAIR: That makes eminent sense. Thank you very much, Mr. Clarke.

JOHN WIEDMAYER, Solemnly Affirmed:

CRAIG FLEMMING, Solemnly Affirmed:

BLAKE WILLIAMS, Solemnly Affirmed:

MICHAEL WILLETT, Solemnly Affirmed:

JONATHAN MacINTOSH, Solemnly Affirmed:

THE CHAIR: And Mr. Clarke.

MR. CLARKE: Thank you, Mr. Chair.

EXAMINATION ON QUALIFICATIONS BY MR. CLARKE

Q. Mr. MacIntosh. Mr. MacIntosh, you're the Director of Enterprise Asset Management; is that correct?

A. (MacIntosh) Yes, that is.

Q. And you've testified before this Board before, including last year's ACE and FAM Audit hearings?

A. (MacIntosh) Yes, I testified in those proceedings, as well as previous FAM and ACE proceedings.

Q. Can you remind the Board of your

background and experience, please?

A. (MacIntosh) Certainly. I'm currently the Director of Enterprise Asset Management for Nova Scotia Power. I'm responsible for leading strategic asset management planning, which includes the development of risk mitigation plans and associated capital investments across the organization.

With respect to prior roles with Nova Scotia Power, I joined the company in 2013 in the role of Senior Engineer, Chemical Assets, where I managed various asset integrity programs. Since then, I've held several roles in the company with increasing responsibility in the field of asset management. My primary focus has been on advancing and standardizing asset management methodologies across the enterprise.

Prior to joining Nova Scotia Power, I held several roles with GE Power and Water, where I led commissioning of large-scale water treatment projects and engineered solutions for the process industry. All told, I have over 15 years of experience in the electric and energy sectors. I'm a Professional Engineer registered in the Province of Nova Scotia, and I hold a Bachelor degree in chemical engineering from Dalhousie University.

Q. Thank you.

Mr. Wiedmayer. Mr. Wiedmayer, can you indicate to the Board your position at Gannett Fleming?

A. (Wiedmayer) Yes. I am the Senior Manager -- Senior Project Manager -- I'm sorry; there's a echo on my end. I'm Senior Project Manager of Depreciation Studies for Gannett Fleming Valuation & Rate Consultants LLC.

Q. Are you still getting the echo, or is everything okay at your end?

A. (Wiedmayer) I'm still hearing an echo, yes. Do you hear an echo, or is it just me?

Q. We don't hear the echo.

A. (Wiedmayer) Okay.

Q. Are you able to proceed?

A. (Wiedmayer) Yes, I'm able to proceed. It's a little bit distracting but if you could bear with me, I'll try to muddle through it.

Q. All right. What are your professional qualifications as Senior Project Manager of Depreciation Studies?

A. (Wiedmayer) I received my four year engineering undergraduate degree from Lafayette College in engineering, with a minor in business statistics. I also received my Master's degree in business administration from the Pennsylvania State University. I'm a certified depreciation professional.

Oh, the echo went away; that's great. Okay. Whatever somebody did that was excellent.

So I am a certified depreciation professional. Can you still hear me?

Q. Yes.

A. (Wiedmayer) Okay, thank you. I'm a member of the National Society of Professional

Engineers, the Pennsylvania Society of Professional Engineers. In 2005, I was elected President of the Society of Depreciation Professionals, which is an organization of members from the utility industry in gas, electric, water, telephone, as well as consultants like myself, as well as staff members from regulatory bodies throughout Canada and the United States.

Q. Mr. Wiedmayer, you have previously testified before this Board as an expert witness in depreciation; is that correct?

A. (Wiedmayer) Yes, that is correct. I've testified before this Board on behalf of Nova Scotia Power in 2003 and in 2011.

Q. And can you tell the Board, please, what does Gannett Fleming do?

A. (Wiedmayer) Yes. Gannett Fleming is an international and management consulting firm, with offices in Canada and the United States, as well as other countries, that has been in existence since 1915. We've been conducting depreciation studies for utility companies since our firm's inception in 1915. We also prepare cost-of-service allocation and rate design studies, rate of return studies, lead lag studies, and present expert testimony in support of those studies.

[2:10:01] **Q.** Gannett Fleming has done depreciation work for Nova Scotia Power since 2001; is that correct?

A. (Wiedmayer) Yes, that is correct.

Q. In your capacity as Senior Project Manager of Depreciation Studies with Gannett Fleming, did you prepare the Depreciation Study for Nova Scotia Power, which was related to its electric plant as of December 31, 2023?

A. (Wiedmayer) Yes.

Q. Mr. Wiedmayer, the 2023 Depreciation Study was filed with the Board and is contained as Appendix 8A of the Application; is that correct?

A. (Wiedmayer) Yes, that is correct.

Q. And do you have any revisions to the 2023 Depreciation Study at this point?

A. (Wiedmayer) No, I do not.

Q. And do you adopt the 2023 Depreciation Study, Mr. Wiedmayer, as your sworn evidence today?

A. (Wiedmayer) Yes, I do.

MR. CLARKE: Mr. Chair, Nova Scotia Power requests that Mr. Wiedmayer be accepted as an expert witness in the area addressed in his evidence; specifically depreciation, and the Depreciation Study, GRA Appendix 8A.

THE CHAIR: Any questions on qualifications, or objections?

He is so qualified, Mr. Clarke.

MR. CLARKE: Thank you, Mr. Chair. The Depreciation Panel is available for questions.

THE CHAIR: Consumer Advocate...?

MR. ROBERTS: No questions.
Thank you.

THE CHAIR: Small Business Advocate.

CROSS-EXAMINATION BY MS. MacADAM

Q. Good afternoon. I just have a few questions with respect to securitization. In the Application, and we can bring it up if you like, you reference:

> As described in Section 9.2, if securitization of the unrecovered net book value of generation assets within the scope of the DDA is delayed such that it cannot be completed in whole or in part by January 1, 2026, [Nova Scotia] Power is requesting that depreciation expense and financing costs of these assets be deferred at WACC on an interim basis.

That was one of the requests from this Board?

A. (Williams) Correct. The passage from pages 52, crossing over to 53, in the Application.

Q. Okay. And the Settlement Agreement that's at N-27, NSEB IR-1, the attachment, states:

> [Nova Scotia] Power will make best efforts to finalize and apply prior to January 1, 2026 for approval of its proposed

securitization of assets, cost of service treatment and the Securitization Rider. It remains open for all Parties to take any position they so choose in relation to such an application.

And that was agreed to between the parties that signed the Consensus Agreement?

A. (Williams) Correct. That -- the excerpt you just read is from that Consensus Agreement.

Q. And there is nothing in the Settlement or Consensus Agreement with respect to the requested deferral that's included in the Application.

A. (Williams) Correct.

Q. I can bring this up if you like. It's a response in -- with respect to the NSEB's IR-89 in Exhibit N-27. The Board asked a question about NSPI's belief of the timing of the Securitization Application, and in response to that question, NSPI indicated that it, "...anticipates a securitization application to the Board in Q4 2025, with securitization in place by the end of Q1 2026." Do you recall that response?

A. (Williams) Yes.

Q. There was no filing in Q4 of 2025. Do you have a revised timeline with respect to the Application?

A. (Williams) It's our hope that we would certainly have securitization in place as soon as possible, and I think an appropriate window for that at this point would be, given that we're in January of 2026, I would say the first half of 2026 to have that application made, determined, and, if successful, securitization in place.

Q. Okay. So not just -- so the application itself prior to -- sorry; in time for the actual decision to be made and securitization to be in place by the middle of the year?

A. (Williams) I think at this point in time, Ms. MacAdam, that's a reasonable ballpark.

Q. And I know there's been discussion through the Application other documents with respect to NSPI kind of waiting for the Regulations with respect to the securitization. What is the current status of the Regulations?

A. (Williams) The Regulations are with government, effectively. So Regulations obviously need to be put into effect from the provincial government, and so we're waiting for that to occur.

Q. Do you have any idea of how long that might take?

A. (Williams) I don't have any specifics on that, and that's why I was kind of trying to give a general timeline in terms of front half of this year to make the application, have it determined and have securitization in place.

Nova Scotia Power certainly has made efforts and will continue to make all efforts to ensure that as soon as we're able to move forward with that application we would do so without any delay.

Q. And just to be clear, do the

Regulations have to be in place and enacted prior to your making the application?

A. (Williams) Yes, I believe so. The relevant provision of the PUA, which would also need to be enacted and would -- is very broad and very general and just provides for the issuance of Regulations, and the Regulations would provide the basis for that application.

Q. Okay. And also in response to NSEB IR-89, the Board asked a question about the deferral in the event of securitization. And NSPI indicated that the deferred costs would be added to the balance to be securitized.

I just want to confirm, so right now, as of kind of January 7, 2026, the rates that are in place are the ones that were in place for 2025; correct?

A. (Williams) They're -- so when you say, "the rates," you mean general rates.

Q. Correct.

A. (Williams) Yes, the general rates are unchanged since 2025.

Q. Okay. And within those general rates, depreciation expenses and financing costs of the assets in the DDA are included in those general rates; correct?

A. (Williams) Sorry, Ms. MacAdams. Can you just give me the question one more time to make sure I'm responding directly to it?

Q. Sure.

So the depreciation expenses and financing costs for the assets of the DDA were included in those rates that were confirmed for 2025 in the previous GRA, technically 2024, but in the previous GRA, and they still continue to be collected as of today.

A. (Williams) So the financing and depreciation costs of the assets that are being proposed to be securitized, which are generally those assets that were considered in relation to the DDA, those costs would have been included in the revenue requirement that would have been put forward for the ’23-24 General Rate Application. As we’re all aware, that Application -- the non-fuel component of that, non-DSM, non-fuel component of that, was capped, so arguable, I suppose, as to whether you can say that those costs are definitively in electricity rates today.

Q. Would you agree with me that some portion of them are included within the general rates?

A. (Williams) I suppose that’s how you would determine what was over the cap and what was under that cap. As I said, it would have been in the revenue requirement that was proposed, but that non-fuel portion was capped.

Q. Okay. With respect to the requested deferral given the securitization has been delayed, what would be the starting date for any deferral period that you’re proposing?

A. (Williams) What we are asking is that that deferral begins as of January 1, 2026 for those costs and that those costs would be included in a deferral as of that date and carried forward.

[2:19:54] **Q.** So how would NSPI account for any of the financing and depreciation costs that were included starting January 1st as part of the previous GRA's general rate and what are -- and the costs that are now being proposed to be securitized?

A. (Williams) Sorry, Ms. MacAdam. I'm going to get you to repeat it again. I apologize.

Q. Sure.

So we were talking about the fact that, arguably, there's some amount of depreciation of financing costs for the assets that are being proposed to be securitized within the rates that are being charged as of January 1st, 2026, which we understand you propose to have those adjusted, but now you're saying that you want the deferral to be effective as of January 1st, 2026.

So right now, NSPI is arguably collecting those financing and depreciation costs but are also asking for an additional deferral to start January 1st, so I'm wondering what the accounting would be to ensure that ratepayers aren't double paying for those depreciation and financing costs.

A. (Williams) Yeah, and I understand your question.

I think the ask is that those costs -- the Settlement Agreement was -- was arrived at with the assumption that we would have securitization in place earlier than we do, based on the discussion you and I just had, and that that would provide relief in the form of addressing those costs and taking those costs out of rate base.

That hasn't occurred, and so Nova Scotia Power is seeking to defer those costs. As I said, and as you acknowledge, your qualifier, arguably, those costs, whether they're in rates now or not, is debatable. I acknowledge your concern, I believe, which is why would we defer those costs if they are already in electricity rates.

Nova Scotia Power's view, though, is that it has made assumptions, made concessions in the Settlement Agreement to reduce costs on the assumption, though, that securitization would be in place. With securitization being delayed, Nova Scotia Power continues to incur those costs, and it will -- it will be a material impact for Nova Scotia Power financially in the first quarter of 2026 to the tune of roughly $18 million will be the cost to Nova Scotia Power.

Q. So does that 18 million take into account what is being collected by Nova Scotia Power with respect to the 2025 rates and any -- as we talked about, arguably, any amount that may be collected for those depreciation or financing costs?

A. (Williams) I would view it as being, as I said, questionable as to whether those costs are in there in the first place, if they are in there. And yes, we'd be asking to defer costs that are in electricity rates.

Q. Sorry. So you're saying it's -- you talked about arguably therein. Is there any way to determine whether or not? Like, can you provide a calculation of what would be collected in that first quarter?

A. (Flemming) So in terms of trying to determine how much we're collecting for the depreciation and financing costs associated with the DDA, there's not an easy way to do that. And so just to give a little bit more detail on that, we -- when we set our revenue requirement, you know, if we do not receive the -- if we do not receive full recovery, which was the case after the last General Rate Application, it's really difficult to match each of those dollars and say, "Okay. So we know that we didn't recover what we expected to be the full cost of service. Where did that come out of?" You could allocate it *pro rata*, and if you were to do that, you would note that, you know, so we are recovering some portion of those depreciation and financing costs, but there's other areas of the business not just the depreciation and financing costs associated with those assets, but depreciation and financing costs associated with other assets, OM and GP, that has not been recovered.

And so when you take the sum total of that, and as we've presented in our cost of service and our revenue requirement, Nova Scotia Power does not have sufficient revenue to recover its cost of service. And as my colleague, Mr. Williams, has stated there, we've looked at this and it is a very material impact to Nova Scotia Power. If Nova Scotia Power were to forego -- so for example, we say forego deferral of depreciation expense and financing cost for the first quarter, if we were to not have revenue as requested until, let's say, the first -- until April 1st of 2026, it is a very material impact to Nova Scotia Power and would approximate actually offsetting completely all of the revenue -- non-fuel revenue that Nova Scotia Power has requested for 2026, putting us back to really no further ahead whatsoever.

So I understand your point, that you could do, like, a *pro rata* allocation, but I think it doesn’t take into account the fact that there’s other costs that Nova Scotia Power is also not recovering for. And so taken at the sum total of that, it would be a very significant impact.

Q. So you -- so I guess what I’m taking from that is that there is some amount that is being collected, but there’s no way to definitively state how much that amount is, because all aspects are kind of missing recovery?

A. (Flemming) That’s certainly fair, to say it that way. Again, it’s -- once you’ve set your revenue requirement, if you don’t receive full recovery, again, you could *pro rata* and say, “Okay, we’ve got -- you know, making up a number here -- 40 percent of this and we’ve got 60 percent of this,” that type of thing. But at the end of the day, when we look at the total cost of service and we look at the total revenue that Nova Scotia Power forecasts for 2026, it's clear that the company doesn't have or doesn't expect to have their revenue to cover its cost of service, and that's one of the primary reasons for the proposed deferral.

Q. So would there -- I mean, when we're talking about 18 million for one quarter that you're putting in deferral, is there any way for you to give even a percentage of that 18 million, whether it's your *pro rata* approach or another approach, that would give some indication of what you are collecting for that? Because I'm trying to figure out, when you're saying you under-collected on what you needed, if we're talking 18 million for one quarter, did you under-collect by 10 percent? By 20 percent? I'm trying to get an understanding of kind of what the quantity is.

A. (Flemming) I think, Ms. MacAdam, you know, again, when we look at the revenue, right, a dollar is a dollar. You know, you could certainly make some assumptions to say, "Okay, well, under this set of assumptions, this is how much of the cost associate with the assets within the scope of the DDA that are being recovered," but at the end of the day, we really do look at it on a total -- the sum total of the cost-of-service basis.

Q. So there's no way for you to kind of give an estimate based on those assumptions?

A. (Flemming) I mean, based upon assumptions, certainly you can place a set of assumptions and say, "Okay. If we said, okay, on a *pro rata* basis, Nova Scotia Power received X-percentage of the non-fuel revenue requests at the conclusion of the last GRA," and you *pro rata* allocated that, you could do some sort of allocation, but in practical application, I'm not sure that we really look at it that way. At the end of the day, it's -- the reason we're asking for it is because it is a material amount that Nova Scotia Power, if not for deferring, would be quite far from being able to cover its cost of service in 2026.

Q. Would you be prepared to provide that *pro rata* estimate?

A. (Flemming) Just one moment, please, Ms. MacAdam.

Q. Sure.

[2:30:00] **A.** (Williams) Just before we respond about the undertaking, Ms. MacAdam, I think really what this amounts to is that, you know, the Application was made, it was made on the consensus -- based on the Consensus Agreement, and it was made with the assumption that certain things would be in place at certain times, it was made on the assumption that there would be a certain revenue requirement in place for the test period. What this ask really is about is about ensuring that that is retained, that that -- those assumptions and that that revenue requirement is retained throughout the test period, so in ’26 and ’27. And that the full costs that were assumed to be recovered in the Consensus Agreement in the Application are recovered during the test period. And that is what this helps to do. It will not make up the difference entirely. We're not seeking to have, you know, lost fixed-cost recovery included in this. It's just those costs that are associated with securitization. And we view that distinction as being relevant because the securitization, the timing of that, is really not within the control of Nova Scotia Power.

Q. Appreciate that. I'm just looking -- you're right, the Consensus Agreement was agreed to on the basis of an assumption. That assumption has not come to fruition. And I'm not going to say who is to fault that; it is what it is. And I'm just looking to ensure that the impact of that assumption not coming true is clear to everyone. And I think the clarity that we're missing is what is being collected? And I can't tell you what is. It's just understanding what is being collected, to the best of your ability, so that -- to ensure that there is no duplication of collection.

A. (Williams) Yeah, and I think what we would suggest is that it is the $18 million. So the depreciation and financing costs associated with those -- that securitized tranche of rate base. And I know we've had the discussion about what is in, what is not, but when we frame this up as looking to ensure that the expectations that went into the development of the Rate Application are met, then it's -- that 18 million is a portion of what those expectations would be already.

So to take that down further is what I'm struggling with. And I go back to the undertaking that you requested. And so I would hesitate to do that, because we would just be making up assumptions and a number, when really, this is a more principled way to go about it, to say, "Well, we're going to talk about the securitization costs and only those costs related to it. We're not going to get into other fixed cost recovery that would occur if rates were in place earlier."

Q. But isn't it fair to say that as

part of the Rate Application, when you were doing the securitization, you took those depreciation of financing costs that were in the previous general rates out of general rates because you were securitizing?

A. (Williams) That is fair.

Q. And so my question is, is because those rates are still in existence now, what are they? So that we can understand that you're not double collecting if you start -- if you were to propose that the deferral costs -- the deferral starts the date that the new rates come into place, then there would be no potential crossover. I appreciate what you're saying is that because the current rates in place today were capped, you may not be collecting all that you expected to collect as you set out for securitization. I'm just looking to understand what that differential is, if you're looking at January 1st?

A. (Williams) Yeah, and I understand. And I understand maybe your frustration with us at this point, but it's not -- not trying to dance around the question. It's just a matter of the fact that those are true costs, and if we had an approved revenue requirement that included those from General Rate Application then we would be able to say definitively yes, it's, you know, 10 million in financing and 6 million in depreciation, or some variation of that. But because of the scenario we're in coming out of that last General Rate Application, I'm not able to tell you specifically what would be in rates or what wouldn't be. And that's -- as you said, we don't need to get into necessarily the reasons for that. We all know rates were capped. It was not a fully funded electricity rate. And so, as a result, there isn't a definitive number that I can give you. If the insistence is for a number, it would just be purely made up, and I don't know that there's a value in that.

And that's why I'm trying to frame it a bit differently where it's not about that necessarily, from our perspective. It's about fully funding the '26 and ’27 test period to the best ability that we can. And that’s not going to happen because of the timing of when we’re going to get rates and the fact that securitization has been delayed. And so we understand the role we play in the timing of rates.

We don’t have the same control when it comes to the securitization, and that’s the distinction and that’s why I’m drawing that distinction. And that’s why we think it’s reasonable to make the ask in relation to the securitization.

We’ve not extended that to the additional fixed cost recovery because, again, we understand the role that we play in that.

Q. I understand what you’re doing and what request is put forward.

So we talked about two different things. One, we talked about pro rata kind of estimation of what may be in the rates for those two -- for the finance and depreciation, and we also talked about what would have been taken out of the rate as a result of the securitization for this Application. Is there something you can give us that provides a range of what we're talking about? Because I have no ability to say is it $1 million, is it $50, is it 18 million. I don't know.

So is there some way that you can give us some -- and appreciate that it would be -- it would not be a specific number, it would not be something concrete, but to give us at least an idea of what we're looking at in terms of magnitude.

A. (Williams) Yeah. Again, Ms. MacAdam, I understand what you're asking and, I mean, we could give you a range, but it would be making up a number. It would not serve -- I don't think it would help things in this discussion because the -- because of the way rates were capped, it wasn't specific to line items or specific to areas of cost. It was an overall cap, and so what is in and out is not something we're able to definitively determine and give you a number on.

So again, that's why I'm trying to frame the question -- or the conversation of it differently where it's about the test periods, about the '26 and '27 test period, and trying to make up the ground that's been lost by the delay in the securitization.

THE CHAIR: Is it the delay in the securitization or is it just the fact that you haven't brought your Rate Application early enough to have it determined by January 1st?

MR. WILLIAMS: So I think -- and that's the distinction that I'm speaking to, sir.

I think we understand that there's a need to bring timely applications to get rates in place, and so that's one of the reasons we're not talking about fixed cost recovery or, you know, costs lost as a result of the timing of the Rate Application. It's more so the impact of the delay in securitization.

THE CHAIR: So I guess if it was securitized on the timeframe and your Rate Application was delayed, you would have still gotten the benefit of that.

MR. WILLIAMS: Potentially. I mean, that's something that would need to be determined as part of the securitization application itself, but yes.

THE CHAIR: So is the premise you're treating it as if securitization occurred on January 1st?

MR. WILLIAMS: Yeah, I think effectively that -- and I see Mr. Flemming leaning in, so I'll maybe stop and just confer with him before I continue. Just give me one moment.

Yeah. And I don't think it's -- I mean, you can look at it both ways, both side of the same coin perhaps, whether it's assuming it did happen or whether these costs are being incurred because it didn't happen, it's the same effect. But yes, the assumption was made that we would have it in place by Jan. 1. And as I said, that's a component of this Rate Application that's not within our control, the timing of it, and so that's the distinction that I'm trying to draw.

THE CHAIR: So at the end of the year when you calculate your return on equity, would you make the same assumption, that the $704 million was excluded from rate base as of January 1st?

[2:40:07] **MR. FLEMMING:** Mr. Chair, I'm wondering -- the question that you're asking is would we remove the $704 million from rate base, but what we're saying is the costs are being incurred because we still have the $704 million in rate base. So maybe I'm misunderstanding what the question is.

THE CHAIR: No, I think you've got the question. I guess the costs are being incurred because you still have it in rate base.

MR. FLEMMING: We're still incurring the costs, the financial costs, for sure.

THE CHAIR: But you want those costs to be put in a deferral account and treated differently because it's still in rate base. And I guess I'm wondering if the same -- you know, if we should also be treating your return on equity with respect to that amount differently as well because you're getting the benefit of allowing those costs to be put into a deferred account for later recovery. Otherwise, you'd just be absorbing them; right?

MR. FLEMMING: So Mr. Chair, I understand the point.

Again, what I think my colleague, Mr. Williams, was trying to convey was that, you know, we still have these costs, we still have these financing costs because of the fact that the securitization has not happened yet, and really out of Nova Scotia Power's control. And so what we've done as part of this Application is proposed to defer those so that we weren't building those costs in for customers in the current period and, instead, recovering those over time through the securitization bond.

You know, I understand the point, but I think what we're trying to convey is that we do still have these real financing costs associated with the delay in securitization and, because of that, we're looking to defer because we do not have the -- we do not project to have the revenue to recover that cost of service.

THE CHAIR: But they're not new costs. You're going to incur them anyway.

MR. FLEMMING: I agree with that. And I think what we're saying is we did -- we developed the Application under a certain set of assumptions expecting securitization to be in place, and that was really a key part of how we came to the proposal that is in front of you today. In order to keep our rates lower, we said, okay, we believe there is the possibility that there's going to be some variance between the timing of when securitization is expected and when it actually occurs, and instead of building in an estimate into our Rate Application for that, we propose to defer that and only pass on the actual cost to customers to be recovered through time over the securitization bonds.

THE CHAIR: Right. You're asking the Board to -- once it approves the deferral, to retroactively include costs that you've already incurred.

MR. FLEMMING: Asking the Board, yes, to let us defer financing costs that we are currently incurring on this amount to be recovered over time because, again, we're showing that we do not have the revenue requirement to -- we don't have the revenue.

THE CHAIR: And had you brought your Application earlier, you would have, assumably, depending on the Board's decision.

MR. WILLIAMS: I don't think it had -- so the securitization aspect of this would still be outstanding. So if your point is if rates were approved Jan. 1, then those costs would have been taken out regardless of whether securitization had occurred or not. Is that ---

THE CHAIR: The question of the deferral would have already been determined, too, then.

MR. WILLIAMS: In that scenario, we would have had -- if we had a mismatch if rates are in place on January 1 and securitization, let's say, happens April 1st, then you would have the costs -- the depreciation and financing costs that we're speaking to, they would have been already removed from rates; correct? That's what you're ---

THE CHAIR: They would have, yes.

MR. WILLIAMS: I'm asking if that's the question, sir.

THE CHAIR: Well, no. I guess it was a timing thing. But anyway, I think I -- you know, I understood the position as Mr. Flemming has described it. I think he's addressed the question. I'll have to think about it, anyway.

Sorry, Ms. MacAdam. I didn't mean to step all over you there.

MS. MacADAM: That's no problem.

BY MS. MacADAM:

Q. I just -- I have one more question.

The request for the deferral is asking to be deferred at WACC, and I'm just wondering what the reason is for the request for WACC.

A. (Williams) So Ms. MacAdam, I think it's the conversation that we just had.

So Nova Scotia Power has these assets that it is incurring financing costs on right now, so Nova Scotia Power is financing them and the WACC would be equal to those financing costs that Nova Scotia is currently approving, so what Nova Scotia Power is asking to do instead of building that amount into rates that it expects, it is proposing to defer the actual financing costs and recover that through the securitization.

Q. Thank you. Those are my questions.

THE CHAIR: Afford Energy Coalition?

Industrial Group?

CROSS-EXAMINATION BY MS. RUDDERHAM

Q. Good afternoon. I'm going to be asking some questions on behalf of the Industrial Group.

I wanted to start with reference to Dustin Madsen's evidence at Exhibit 34, which I don't think we need to bring up right now. But have the members of this panel reviewed the evidence of Dustin Madsen regarding the Depreciation Study criticism?

A. (Flemming) Yes, we have, Ms. Rudderham.

Q. Fair to say that he's critical of the use of NSPI's utilization of the Equal Life Group, or ELG, methodology versus the Average Life Group, ALG, methodology?

A. (Flemming) I think Mr. Madsen recognizes that both are used in a number of jurisdictions across North America. He does certainly recommend that the Board direct Nova Scotia Power to adopt the Average Life Group in this case.

MS. RUDDERHAM: Okay. Mr. Goodine, if you don't mind bringing up that exhibit, so that's Exhibit N-34. And I'm looking at PDF page 50, and Table 4.

There we go.

BY MS. RUDDERHAM:

Q. Now, Mr. Madsen here provides the financial impact of moving to ALG and how it reduced the total 2026-2027 depreciation by 23.3 million in 2026 and 24.3 million in 2027. Do you see that there?

A. (Flemming) Yes, I do, Ms. Rudderham.

Q. Now, has NSPI validated these numbers or compared these numbers?

A. (Flemming) Yes, Nova Scotia Power provided these figures.

Q. Sorry; you said you provided these figures to Mr. Madsen?

A. (Flemming) To Mr. Madsen, yes.

Q. Okay. And are you able to

clarify just what the impact would be on NSPI's FFO-to-debt metrics if this change was implemented?

A. (Flemming) So it would certainly reduce Nova Scotia Power's FFO-to-debt. It would make the credit metrics fall or be lower.

To what extent or how much that would change, I have not done that math, but it would -- it would have both the impact of decreasing Nova Scotia Power's cash flow or funds from operations, FFO, and it would also have an impact of increasing Nova Scotia Power's debt because a portion of the capital assets are funded with debt.

So it would be decreasing on the numerator and increasing on the denominator.

Q. Thanks for clarifying that.

Now, in preparing the Depreciation Study that's on the record today, would you agree that there were some limitations on what the actual data was available in relation to transmission and distribution assets?

[2:50:08] **A.** (Flemming) In what way, Ms. Rudderham?

Q. NSPI has actual data dating back to 2009 when there was a shift to fix asset system but not before that. Is that a fair ---

A. (Flemming) Yes. I think I'd have Mr. Wiedmayer speak to this question and give a little bit more detail.

A. (Wiedmayer) Okay, yes. In past depreciation studies where the depreciation rates were approved by the Board, the underlying data that we utilized was unaged property accounting records of the company going back to many decades, most likely starting in around 1942 for most of the accounts. Obviously, some of the newer accounts, like smart meters, things like that that weren't around, you know, we have a shorter period of time for that data to exist.

But the unaged property accounting

data, which means that we don't really have a record of when -- the property that was retired, when it was originally installed. However, we do have a record of each year of the property additions and retirements made for each asset group.

And we're able to simulate aged -- an age balance and an age retirement data from the property accounting history of the company, and then once we have a simulated aged retirements and simulated balances, the actuarial techniques that we utilize for aged data can be also used for the simulated aged data.

Q. Okay. And I'm not sure -- that was a helpful answer, but I'm not sure it answered the question I was asking.

NSPI has actuals dating back to 2009 in relation to the transmission and distribution assets; correct?

A. (Wiedmayer) Yes, that's correct.

Q. Okay.

A. (Wiedmayer) Mr. Flemming, were you about to answer?

A. (Flemming) No, that's great, Mr. Wiedmayer.

MS. RUDDERHAM: I don't think we need the exhibit up here, so then that way we could see Mr. Wiedmayer better.

Thank you.

BY MS. RUDDERHAM:

Q. And Mr. Wiedmayer, would you agree that the passage of time will allow NSPI to rely more heavily on its actual historical data rather than simulated data?

A. (Wiedmayer) Yes, I would. The passage of time will help. As we get more years of experience with the aged data, I think it would become more useful to use.

However, let me add this caveat. In 2008 and 2009 when the company installed their new fixed asset database, there were assumptions that were made about the existing age of transmission and distribution plant assets in place because throughout the previous 40, 50, 80 years of the company's history, it did not have an age database that it maintained. So there were some overlying broad assumptions that were made in developing a fixed asset database in 2009 that was properly aged. So I don't want to make it seem as though in 2009 we were able to know with perfect insight the actual age of all the assets that were in service.

Q. If a new GRA, or the next GRA, were to be filed in 2028 or 2029, NSPI would then have nearly 20 years of data, actuals; correct?

A. (Wiedmayer) Yes.

Q. And ---

A. (Wiedmayer) With the same caveats in the sense that there are limitations to the starting age balance at 2009. Obviously, in 2009, you have assets that are one year old to 80 years old that have to be aged. And somebody in 2009 had to perform that test. The records weren't always perfect.

And so going forward, I do think the age database will become useable, and maybe more reliable than it is. However, let's just start with the understanding that we're not -- we don't have perfect data in 2009.

Q. Fair. But in your experience, is 20 years of actual asset performance data generally considered a reasonable timeframe for conducting analysis of asset lives?

A. (Wiedmayer) It depends on the property account. Twenty (20) years would be sufficient if we were undertaking an actuarial analysis of, let's say, vehicles or work vehicles that typically have an average service life of 12 to 15 years. Something like transmission towers that have a much longer life, you know, maybe 20 years doesn't capture all of the information needed. But I would say for most -- I would say most accounts, 20 years would be probably the minimum that I would rely upon.

Q. Thanks.

A. (Wiedmayer) With the exception of some of the longer-lived accounts such as towers and some other transmission, plant accounts, overhead conductors.

Q. And are you aware that the new ISO Nova Scotia is currently undertaking its own IRP process?

A. (Flemming) Yes, we are aware of that, Ms. Rudderham.

Q. Okay. And the IRPs typically includes assets and projections regarding the retirement dates of generation assets; correct?

A. (MacIntosh) Yes, that's correct, Ms. Rudderham.

Q. And those assumptions from an IRP are generally used in depreciation studies regarding generation asset lives that are targeted in the IRP.

A. (Flemming) Ms. Rudderham, I'd agree that, in many cases, the life expectation in the IRP would be used as the basis for the final retirement date. However, that would still need to be supplemented with data related to interim retirements within the plant.

Q. Would you agree that having a completed and approved IRP would provide better data for making some of those assumptions about generation assets in the future Depreciation Study?

A. (Flemming) So I would say that newer, more up-to-date information is always better, certainly. But I also think that you do have to use the estimates, the best estimates that you have at a certain point in time. And so the normal course of the Depreciation Study is to take your best estimates that are available to you at that time and then to update those estimates in the future on a periodic basis to true up your book depreciation as compared to your theoretical book depreciation.

Q. Okay. So you'd agree, then, that having an updated approved IRP that's currently being prepared by the ISO Nova Scotia would provide better information on making some of those assumptions in the Depreciation Study.

[3:00:04] **A.** (Flemming) I think updated and approved estimates are going to be more up to date than estimates that are a little bit older. And so I think that's a recognized part of depreciation studies and, you know, updating those on a periodic basis to reflect the latest and most up-to-date information that's available at that time.

Q. And without agreeing or disagreeing to the use of ALG methodology, is it fair to say that if the Board were inclined to review the methodology used, it would be better informed to compare the choices at a future time when there is more actual data available and the completed IRP?

A. (Flemming) So it's a good

question, Ms. Rudderham, and I think that we're always going to have a mismatch of information. You're always going to want more up-to-date results or more up-to-date estimates.

You know, I think that in terms of the timing, you know -- I think Nova Scotia Power, for the generation assets that are near term, the company has a good understanding of the timeline associated with those and are -- have the DDA mechanism in order to recover that. For some of the longer-lived assets, I'm not sure that it would make a significant difference in terms of the timing of the retirement. I think that the difference between the ALG and the ELG would actually be much more significant in terms of the differentiation in terms of the -- how much depreciation expense would be recovered.

Q. Yeah. I guess what I was asking was would it be beneficial to have that data, like the current -- or the up-to-date IRP and more aged data dating back to 2009 in order to do that comparison between ALG and ELG?

A. (Flemming) Yeah, I think more information, more actual data and, you know, more up-to-date estimates is always useful, Ms. Rudderham.

Q. Those are all my questions. Thank you so much.

THE CHAIR: Municipal Electric Utilities?

MR. MacDUFF: No questions, Mr. Chair.

THE CHAIR: Department of Energy?

MR. BOYLE: No questions. Thank you, Mr. Chair.

THE CHAIR: Port Hawkesbury Paper?

MR. MacDOUGALL: Mr. Chair, I only had a few questions related to securitization which I was going to do on a later panel, but since the topic has already been raised, I think it would be efficient to actually do them now.

THE CHAIR: I have no objection if the panel doesn’t, although I probably will have some for a later panel myself, but. Yeah, and the Vice Chair does as well. So we will be coming back to it, but whatever your preference is, Mr. MacDougall.

MR. MacDOUGALL: I think they tie in to sort of the questions from this morning, so I’ll do them now. And again, I may have a few at the later panel as well, but I think it may be useful for efficiency on some of the questions to do them now, Mr. Chair.

THE CHAIR: Mr. Clarke.

MR. CLARKE: Well, as always, it's the pleasure of the Board. I guess my gut reaction would be to try to keep it all sort of in one area of questioning, rather than break it up and split it up. To me, that's a more reasonable approach, and it, I think, would be a little easier for the panel members. If we're going to deal with it, let's deal with it and let's get it -- all the questions asked sort of during the same timeframe.

THE CHAIR: Mr. MacDougall, any

response to that?

MR. MacDOUGALL: No, I'm easy, Mr. Chair. As I say, I didn't anticipate all those securitization questions coming earlier, so now that they have, I'm ready to go on those if you want me to. I'm ready to hold them into another panel if you want me to.

THE CHAIR: Yeah. Well, I know I will have some later, and Mr. Deveau said he will as well. So maybe we'll just hold those.

MR. MacDOUGALL: That's perfect, Mr. Chair. That's why I raised it.

THE CHAIR: Thank you, Mr. MacDougall.

Did I miss anyone before going to Board counsel?

Mr. Mahody.

MR. MAHODY: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MAHODY

Q. Good afternoon, panel. Good afternoon, Mr. Wiedmayer.

A. (Wiedmayer) Good afternoon, sir.

Q. Mr. Wiedmayer, do you agree that the accepted cadence for depreciation studies is in the range of three to five years?

A. (Wiedmayer) Yes, I would agree that's -- that falls within the range of typical periods that are used within the industry for updating these periodic depreciation studies.

MR. MAHODY: Mr. Goodine, could we please call up Exhibit N-24, PDF page 4? It's IR-16, PDF 430, I believe, of N-24.

MR. GOODINE: What's the exhibit?

MR. MAHODY: I had N-24, IR-16, but I'm -- all right. They're Mr. Madsen's responses to his IRs, I believe. Yeah, perfect. Thank you, Mr. Goodine.

BY MR. MAHODY:

Q. So here, Nova Scotia Power was asked to, "...provide copies of all previously filed depreciation studies." And the response includes a single Depreciation Study as of December 31, 2009.

MR. MAHODY: If you could scroll down, please, Mr. Goodine, just to page -- a little bit further on the next page, please. Next page again, sorry.

BY MR. MAHODY:

Q. So here, Mr. Wiedmayer, is your study effective December 31, 2009. Do you see that?

A. (Wiedmayer) Yes.

Q. Right. And just to confirm for accuracy, this is the only Depreciation Study that was filed prior to the one that's at issue in this matter. Can I get confirmation of that?

A. (Wiedmayer) Yes.

Q. And that matter was at -- your December 31, 2009, I'm just going to call it the 2009 Depreciation Study, Mr. Wiedmayer. The matter into which that was filed, do you recall the course that that matter took towards resolution?

A. (Wiedmayer) Yes. There was a Settlement Agreement in 2011 ---

Q. Okay.

A. (Wiedmayer) --- where the parties resolved all the depreciation issues as part of a black box settlement.

Q. Yeah. And before ---

A. (Wiedmayer) The docket number -- yeah.

Q. Sorry; I didn't mean to cut you off.

A. (Wiedmayer) I think (inaudible due to speaking over each other).

Q. All right. And prior, though, to that settlement being proposed and eventually approved by the Board, there was an evidentiary record that had been created where your Depreciation Study had been filed and at least three other experts had filed testimony before the Board as well. You recall that?

A. (Wiedmayer) Yes, I do.

Q. Okay. Do you recall Mr. Chernick filing evidence, Mr. Pous, on behalf of the -- Board counsel, Jacob Pous filed evidence, and Mr. Selecky on behalf of, at the time, NewPage Port Hawkesbury, they all filed evidence.

A. (Wiedmayer) Yes, I recall that.

Q. Okay. And you recall, then, that Mr. Pous, on behalf of Board counsel, his evidence addressed the distinction as between ELG and ALG and what his preference was, do you?

A. (Wiedmayer) Yes, I recall that, yes. That issue was raised in that proceeding with Mr. Pous.

MR. MAHODY: Mr. Goodine, I've sent you a copy of Exhibit N-9 from the 2009 Depreciation Study matter. Could we call that up, please.

BY MR. MAHODY:

[3:10:00] **Q.** So Mr. Wiedmayer, this is Mr. Pous's testimony filed in that matter, and I'd like to take you to PDF page 88, and at line 4, Mr. Pous states:

> This portion of my testimony will address the Company’s request for ELG-based depreciation. I will demonstrate that the ELG calculation procedure represents the best theoretical procedure, but the worst calculation procedure in the real world of utility operation and ratemaking.

You recall that that was Mr. Pous's testimony, part of it, regarding the ELG/ALG issue.

A. (Wiedmayer) I don't recall that specific statement, but yeah, having read it here I accept it. Mr. Pous, that is his opinion. Obviously, it is one that I disagree with.

Q. Understood, and understood completely on that front, sir.

MR. MAHODY: Next, can -- Mr. Goodine, I had sent you Exhibit N-10 from that same matter, which is Mr. Selecky's evidence. And Mr. Selecky, if I could get his evidence turned to PDF page 9, line 7.

BY MR. MAHODY:

Q. Here, Mr. Selecky was asked, "Do you support NSPI's proposal to use the ELG procedure to calculate book depreciation rates?" Answer:

> No. The ELG procedure results in ratepayers paying front end loaded depreciation expense and will likely result in intergenerational inequities because rates are not generally changed annually. Further, [the] proponents of the ELG procedure claim that it more precisely estimates depreciation expense, however, this is not the case.

Do you recall that being part of Mr. Selecky's view in relation to the appropriateness of the suggestion to use ELG methodology? And I appreciate you don't agree ---

A. (Wiedmayer) (Inaudible due to audio quality).

Q. Okay. All right.

A. (Wiedmayer) Yes, I have encountered both Mr. Pous and Mr. Selecky in other jurisdictions, and that statement is not a surprise to me, and you know, obviously I do disagree his statements there.

Q. And Mr. Wiedmayer, are you aware of any other Canadian utility with fewer filed depreciation studies than Nova Scotia Power in the last 25 years?

A. (Wiedmayer) Can you repeat the question, sir, please?

Q. So the evidence in this matter is that there have been two depreciation studies filed over the last 25 years. Are you aware of any utility who has filed -- that has filed fewer depreciation studies over a similar period?

A. (Wiedmayer) There are certain jurisdictions in which the utilities do not have a requirement to file on a, you know, once every five or once every four year basis. You know, they file as they need to with regards to a General Rate Application.

Typically, in the jurisdictions where a five-year standard is not specified, utilities do file an updated Depreciation Study typically when they file a General Rate Application. So for the ones that have not filed for an increase, I would say they would be the ones that would come to mind.

MR. MAHODY: Mr. Chair, just before I change topics, if I could get those two exhibits marked. One is Exhibit N-9 from the previous depreciation matter, and the other is Exhibit N-10 from the same matter.

THE CHAIR: Okay. We'll mark -- was Mr. Pous's evidence was Exhibit N-9?

MR. MAHODY: Correct.

THE CHAIR: We'll mark that one as Exhibit N-44, and Mr. Selecky's evidence -- sorry, N-45 and Mr. Selecky's evidence as N-46.

MR. MAHODY: Thank you.

THE CHAIR: Oh, sorry. I think those are taken with the CVs that were filed. Just give me a second here.

Mr. Pous will be N-48 and Mr. Selecky would be N-49.

--- EXHIBIT NO. N-48:

Direct testimony of Jacob Pous

--- EXHIBIT NO. N-49:

Direct evidence of James T. Selecky

MR. MAHODY: And Mr. Goodine, could we call up Mr. Madsen's evidence, Exhibit N-34, page 25, please?

BY MR. MAHODY:

Q. And I'm looking down at line 13, Mr. Wiedmayer, where Mr. Madsen states:

> Notably, the vast majority of North American electric utilities, by both total investment and overall count, rely on the ALG procedure.

You agree with that statement, don't you, Mr. Wiedmayer?

A. (Wiedmayer) I would say the majority of North American electric utilities rely on the

Average Life Group procedure primarily because Equal Life Group procedure at one time required -- and still does. It requires thousands of individual simple arithmetic calculations to be made. However, with the advent of personal computers, those thousands of calculations can be performed in seconds.

So the adaption of the Equal Life Group procedure did not occur until, really, the Canadian telephone -- the Canadian Bell companies advocated for its use in the 1970s, and then the energy companies followed up shortly thereafter in the ‘80s.

So I would say the Average Life Group has a longer acceptance primarily due to the fact that it was simpler to calculate one single average life and simple to calculate a rate based on that life than the Equal Life Group procedure, which was also referred to as the unit summation procedure, and it requires hundreds of individual arithmetic calculations which can be performed readily today by computers and anybody that has developed the software to make those calculations, which my firm has.

I would say the Equal Life Group procedure is used widely in certain provinces in Canada. Alberta comes to mind. I also know that Newfoundland uses the Equal Life Group procedure. And it has been used for over 30 years in Nova Scotia for Nova Scotia Power.

Q. Is there a correlation, Mr. Wiedmayer, between Nova Scotia Power having used the ELG method and the lack of depreciation studies that have been filed in this jurisdiction, to your knowledge?

A. (Wiedmayer) Yeah, I believe there is a correlation there.

MR. MAHODY: Can we go back to that exhibit, Mr. Goodine, please, and that same line that I was looking at?

BY MR. MAHODY:

Q. So Mr. Wiedmayer, the statement says:

Notably the vast majority of North American...utilities, by both total investment and overall count, rely on...ALG procedure.

You agreed, I think, majority. Are you taking issue with whether or not the vast majority of North American electric utilities rely on the ALG procedure?

A. (Wiedmayer) I'm not taking issue with it. It's just, you know, it's a relative term that I don't quite understand what percentage he means by "vast majority". Does that mean 95 percent of the -- or does it mean 70 percent? That's all.

I'm just taking issue with it's a relative term that I don't really understand what his underlying meaning is.

[3:20:05] **Q.** Okay. Thank you, Mr. Wiedmayer.

Could I turn now to the Consensus Agreement and the section on depreciation?

MR. MAHODY: Mr. Goodine, this is

found at Exhibit N-27. It's the first IR response.

And if we just can scroll down, we're going to come to the schedule with the -- thank you. Yes, here on this page.

BY MR. MAHODY:

Q. And Mr. Flemming, good afternoon. I think this question is for you.

There's reference here to in order to achieve a reduction in depreciation and accretion expense of approximately 20 million per year over the '26-27 test period, and there's reference to Appendix A, which I'm happy for you to take me to. But can you just explain to me what was done in order to achieve the $20 million reduction that's referenced here?

A. (Flemming) Yes, Mr. Mahody, I can do that. And probably best for us to go to Exhibit N-7, Appendix 8G because we have the approach outlined in that document.

So Mr. Mahody, on your screen there,

we've noted the eight different steps that we took in order to achieve a reduction, and so that reduction came out to a little bit under $20 million a year in 2026 on a forecast basis and a bit more than $20 million in 2027 on a forecast basis.

Q. And from an order of magnitude, these steps as you undertook them, are they -- did some of these have a greater impact on reaching your $20 million than others?

A. (Flemming) Yes, certainly they did.

So some of the changes would be quite minor and some of them would be -- was significantly more. We did submit an information response that did break down the impact for all of these steps. However, we did have 1 to 3 all of the costs associated with decommissioning. We didn't delineate between 1, 2 and 3. We did have those all grouped together.

I can look for the information

response if you give me just one moment, please, Mr. Mahody.

Q. Certainly.

A. (Flemming) It would have been our response to Nova Scotia Energy Board IR-87.

Specifically, I'd be looking at IR-87(c).

MR. FLEMMING: Thank you, Mr. Goodine.

So Mr. Mahody, you can see there that the Steps 1 through 3 would have resulted in a depreciation and an increase in expense reduction of $10.6 million and $11.7 million in 2027. So that would be -- those three steps would have been the largest contributor.

You can also see that step 7, which is the reduction in the net salvage rate for transmission poles and fixtures that would have an impact of $5 million in 2026 and $5.3 million in 2027.

BY MR. MAHODY:

Q. Thank you, Mr. Flemming.

Ms. Rudderham had taken you to Mr. Madsen's recommendations regarding the consequences of utilizing the ALG method; that's the 23.3 million in 2026 and the 24.3 million in 2027. If those changes were made -- and you can use 2026 as an example -- can you just step me through what the impact would be in relation to the calculation of your FFO and your credit metrics? So say in 2026, you're taking $23.3 million out of your depreciation expense.

A. (Flemming) So yes, Mr. Mahody, as we discussed, so if we were to move from the ELG to the ALG procedure, it would have lower rates. And the lower rates -- short term lower rates, because it is offset, of course, by less depreciation, less accumulated depreciation, and therefore higher rate base, right? So when you have an Average Life Group, you have lower rates, and therefore Nova Scotia Power would have a higher rate base, right?

So Nova Scotia Power, as Mr. Wiedmayer

mentioned, has had Equal Life Group now for over 30 years. And as some of the consultants, or as Mr. Madsen has noted, and as well as the other exhibits you brought back up from the last Depreciation Study, they state that it's frontloading, but it does -- Nova Scotia Power would collect higher depreciation rates and therefore have the offsetting impact to rate base. And so we would have lower rate base.

So in terms of your impact, it's not just the FFO, it's also the higher rate base impact.

So I have not calculated the exact figure. As I noted to Ms. Rudderham, you would have a higher -- you would have a reduced funds from operation and you would have a higher debt amount. I have not calculated those figures, Mr. Mahody, and I'm hesitant to do it right now on the stand, but certainly could endeavour to do that for you.

Q. Thank you. I appreciate that. I think I know an undertaking when I see it. Can I ask you to make that calculation? And just for context, Mr. Flemming, if I might, if we could call up Exhibit N-3, page 69?

So you're familiar with these Figures, 10-2 and 10-3, Mr. Flemming?

A. (Flemming) Yes, sir.

Q. Okay. So what I'm looking for in this undertaking I'm going to request is for the 2026 and the 2027, for you to be able to demonstrate what those percentages are, having implemented the changes in methodology that Mr. Madsen has identified, the 23.3. Are you with me on this?

A. (Flemming) Understood.

Q. Okay. So for the purposes of the record, is it a matter of recalculating the data that we see in these charts to take into account those two adjustments?

A. (Flemming) Yeah, Mr. Mahody, the way I word it is you're looking for forecast S&P and DBRS cashflow-to-debt credit metrics under the Average Life Group methodology?

Q. I think I am, but I'll know in a moment. Yes, that's what I'm looking for. Thank you very much, Mr. Flemming.

MR. MAHODY: Don't make me repeat that, Mr. Chair.

THE CHAIR: I think Mr. Flemming did a very good job of that. Undertaking U-7.

UNDERTAKING U-7 - To provide the forecast S&P and DBRS cashflow-to-debt credit metrics under the Average Life Group methodology

MR. WILLIAMS: Mr. Mahody, if I may, just before we move on from that, so undertaking that exercise, so a shift from ELG to ALG would have the impact that -- and we'll see what that exact impact is on FFO-to-debt ratios. It -- important for the conversation, important for people to understand, I think, that it has a higher cost for customers over time. So by virtue of the fact that you're increasing rate base or not decreasing rate base at as quick a pace, that has a higher cost for customers over time. And so ALG costs customers more over time.

MR. MAHODY: Thank you.

[3:00:09] Mr. Goodine, could we go back to Mr. Madsen's evidence, N-34, and it's PDF page 73.

BY MR. MAHODY:

Q. And here at Table 8, Mr. Madsen is making a series of other recommendations regarding adjustments to the Depreciation Study as filed. Has Nova Scotia Power calculated the dollar consequences if Mr. Madsen's recommendations were implemented?

A. (Flemming) No, we have not.

Q. And would making that calculation, Mr. Flemming, be something that could be done by way of an undertaking?

A. (Flemming) I'd have to involve

Mr. Wiedmayer here as well, Mr. Mahody.

Mr. Wiedmayer, is it reasonable from your -- reasonable and able to do it in a reasonable timeline, from your perspective?

A. (Wiedmayer) Yes, it is, Mr. Flemming.

A. (Flemming) Thank you.

Yes, Mr. Mahody.

MR. MAHODY: Thank you.

And so Mr. Chair, that is a calculation of the dollar affect of implementing the changes recommended in Table 8.

THE CHAIR: Undertaking U-8.

UNDERTAKING U-8 - To provide the calculation of the dollar affect of implementing the changes recommended in Table 8 using both ALG and ELG

MR. WIEDMAYER: Mr. Mahody, can I ask one clarifying question about that table?

BY MR. MAHODY:

Q. Certainly.

A. (Wiedmayer) Yeah, so Mr. Madsen's recommending lengthening service lives, and a different survivor curve than what the company has proposed. Would you like to see the impact on depreciation expense using the Equal Life Group procedure or the Average Life Group procedure with his recommended -- let's say for account 353, the 50 R2.5 survivor curve calculated using the Equal Life Group procedure, as well as the Average Life Group procedure, or just one of the two procedures?

Q. If you're able to do it for both, I think that would be informative.

A. (Wiedmayer) Okay. Yes, we can do it for both.

Q. Thank you, Mr. Wiedmayer.

A. (Wiedmayer) You're welcome.

MR. MAHODY: Mr. Chair, those are my

questions.

THE CHAIR: All right. Why don't we take a brief break and come back at quarter to 4:00?

--- Upon recessing at 3:33 p.m.

--- Upon resuming at 3:45 p.m.

JOHN WIEDMAYER, Resumed:

CRAIG FLEMMING, Resumed:

BLAKE WILLIAMS, Resumed:

MICHAEL WILLETT, Resumed:

JONATHAN MacINTOSH, Resumed:

THE CHAIR: Okay. We'll pick up again.

Mr. Murphy.

MEMBER MURPHY: Thank you, Mr. Chair.

QUESTIONS FROM MEMBER MURPHY

Q. Good afternoon, panel. I want to start my questions on the GRA and cost-of-service deferral, so probably I would think those questions are perhaps for Mr. Flemming or Mr. Willett. But anyway, you can answer as you see fit.

In the prior GRA, in the 2022 GRA, you'll recall that Nova Scotia Power asked for Board approval of GRA amount, a deferral amount in the amount of $2.5 million; correct?

A. (Flemming) Related to costs -- external costs incurred for preparation and filing and ---

Q. GRA, yeah.

A. (Flemming) Yes. Yes, I do.

Q. Okay. And that was related to consulting services, fees for intervenors, the whole regulatory process for the GRA; correct?

A. (Flemming) That's correct, Mr. Murphy.

Q. Okay. In the current Application, you're seeking a $2 million deferral, but it's related to the -- correct me if I'm wrong, the GRA costs, Cost-of-Service Study, Line Loss Study and preparation of the Climate Adaptation Plan; correct?

A. (Flemming) Mr. Murphy, it does include costs associated with the Cost-of-Service Study, it does include costs associated with the GRA. The Climate Adaptation Plan costs were not included in the $2 million.

Q. Okay. Thank you.

Can you tell me or perhaps -- maybe an undertaking for this, but can you tell me what the costs were for preparation of the Cost-of-Service Study and the Line Loss Study?

A. (Flemming) Mr. Murphy, we'll take that as an undertaking.

Q. Okay.

<u>MEMBER MURPHY:</u> You want me to repeat that, Mr. Chair?

THE CHAIR: No, I think we're good. That's Undertaking U-9.

UNDERTAKING U-9 - To advise the cost of preparation of the Cost-of-Service Study and the Line Loss Study

BY MEMBER MURPHY:

Q. Okay. Thank you.

Can you tell me what the estimate is for the actual GRA deferral cost?

A. (Flemming) The -- in terms of just the GRA or the GRA plus the cost of service?

Q. Just the GRA.

A. (Flemming) I believe, subject to check, Mr. Murphy, it was consistent -- it was approximately 2.5 to 3 million dollars, is what we forecast. We then subsequently reduced the total of the cost of service and GRA deferral in sum total from $4 million down to $2 million.

Q. That’s the total amount for the Cost-of-Service ---

A. (Flemming) That’s the -- that’s the total, yes. We didn’t delineate for the purposes of that. We had a cost of service and GRA deferral. We expected $4 million in sum total, and we reduced that by half.

Q. But you can’t tell me a rough estimate of what the GRA only component of that $2 million is.

A. (Flemming) Of the $2 million?

Just one moment, please, Mr. Murphy.

So again, we, at one point, had 2.5 to 3 million dollars for GRA and then we reduced that amount, so we didn’t -- we didn’t allocate between the Cost-of-Service and the GRA, so because the Cost-of-Service was already done, I would say that that would all come from the GRA, so that would be about a half a million to one million dollars, in that area, would be what we ---

[3:50:13] **Q.** For the ---

A. (Flemming) For the GRA.

Q. For the GRA itself.

A. (Flemming) So it's the remaining, yeah, amount.

Q. Okay. Okay, thank you.

Okay. I'd like to move on to the estimates that were included in the Depreciation Study as they relate to the hydro decommissioning costs.

MEMBER MURPHY: So Jeff, if you could call up Exhibit N-7, PDF page 649, please.

BY MEMBER MURPHY:

Q. And these are the -- as I understand it, these are the estimated full costs of decommissioning for each of the hydro facilities as well as the estimated total partial decommissioning costs for the hydro facilities; correct?

A. (Flemming) Yes, in 2024 dollars.

Q. In 2024 dollars.

And the costs -- the partial decommissioning costs that are noted here are the costs that are included in the Depreciation Study. Of course, there's some other exclusions that were identified earlier in discussion with Mr. Mahody, but these were the base costs that were included in the Depreciation Study, inclusive of the ones you mentioned to Mr. Mahody.

A. (Flemming) That's -- that's correct, yes.

Now, we did remove all the emission costs associated with the Mersey, Wreck Cove ---

Q. Right.

A. (Flemming) -- and Tucket system, but yes.

Q. Right. Thank you.

MEMBER MURPHY: Okay. I'm going to ask Jeff to call up -- it's an Excel spreadsheet.

Before you call this up, Jeff, I just

want to ask the panel a question.

BY MEMBER MURPHY:

Q. It's Excel. It's written in response to NSEB IR-85. It's Attachment 1.

The attachment is -- it's confidential, but if I ask Mr. Goodine to hide some columns there that are confidential, we can see the information that I want to get to. And that material is non-confidential.

So if you're okay with that, I'll ask Mr. Goodine to pull those up.

A. (MacIntosh) Yes, that's okay.

MEMBER MURPHY: Okay, Jeff. So if you could call up -- it's Excel -- or it's Exhibit N-27(ii), NSEB IR-85, Attachment 1.

Before you call it up, if you could hide Columns B through J of the decommissioning summary tab.

(SHORT PAUSE)

MR. FLEMMING: There are as well some columns on the partial infrastructure removed right there.

BY MEMBER MURPHY:

Q. Yeah. I'm just going to show this tab, though.

A. (Flemming) Thank you.

MEMBER MURPHY: Yeah, that's it.

Can you put it side by side, Jeff, beside that?

(SHORT PAUSE)

BY MEMBER MURPHY:

Q. There we go. So I wanted to just look at Bear River and Lequille. If we look at the full decommissioning cost and partial -- let's just look at the partial decommissioning cost. Partial decommissioning cost in Exhibit 80 show 21 million for Bear River, whereas in Appendix 8(e), and I'll just -- or it's not Appendix 8(e), Attachment 1 to NSEB IR-85. I'll just clarify what that attachment responded to. It was IR-85(b). The Board staff had asked Nova Scotia Power to:

> ...provide a detailed breakdown of the...work and costs by component, that have been removed from...'full' decommissioning costs to determine the 'partial' decommission costs?

Sorry, this was for (c):

> Please provide all information and documentation that supports any claim that [Nova Scotia] Power will not be required to undertake 'full' decommissioning [costs]...

Anyway. There's a discrepancy between Appendix 8(e) and what Nova Scotia Power provided in the response to Board IR-85. So it looks to me like there's 21 million, roughly, in decommissioning costs associated with Bear River that's been included in the Depreciation Study, whereas the response to the IR shows roughly 7 million, and then for Lequille, the decommissioning study includes 13.7 million, whereas the response to the Board IR includes 3.2 million. So I'm just wondering if you could square those up for me?

A. (Flemming) Yes, I believe we can.

Just one moment, though, Mr. Murphy. I just want to confer with my colleague, please.

Q. Okay.

A. (Wiedmayer) Craig and Jonathan, there's 14 lines on the one and 11 rows on the other. I think there's a couple of river systems that we've combined.

A. (Flemming) Mr. Wiedmayer, we're -- yeah, we're just making sure we've got the right lines to go with the right spot, but appreciate it.

(SHORT PAUSE)

MR. FLEMMING: Okay. Apologies for the wait, Mr. Murphy. And apologies for the confusion here. So I think we could have been a bit more clear in our response.

So the reason for that is because in the table above, we have grouped some of the river systems together to tie to our asset records. So we're looking at it in two different ways. So I have not been able to check the math in the moment we have here, but ---

BY MEMBER MURPHY:

[4:00:11] **Q.** Well, let me jump ahead of you.

A. (Flemming) Yeah, sure. Go ahead.

Q. I checked the math.

A. (Flemming) Okay.

Q. I used my 40-year-old calculator, 1986, so it doesn't mean it's right.

A. (Flemming) Okay.

Q. It looks like Nictaux, Paradise, and Sissiboo costs are included in the Black River costs. Or they're included in Black River and Lequille somehow. The Exhibit 8(a) is missing Sissiboo and missing Paradise. If you add those costs up together, they'll come to the sum total of 8(e) for Bear River ---

A. (Flemming) Right.

Q. --- and Lequille.

A. (Flemming) So Bear River would include -- so Bear River, in the Appendix 8(e) that we're looking at, but above, should include both Bear River and Sissiboo on the bottom, and then for the total of Lequille, in the top table, that would include the sum total of Lequille, Nictaux, and Paradise.

Q. Okay. Thank you. So just as it relates, I guess, to the Depreciation Study itself, by lumping those together, do the systems for Nictaux, Paradise, and Sissiboo, do they have sort of the same depreciation profile that Black River and Lequille would have?

A. (MacIntosh) Yes, they would have the same retirement profile of the 2066, subject to check.

Q. So they're the same age as well?

A. (MacIntosh) They have different commissioning dates. Mr. Wiedmayer can pull up the accounts associated with those hydro systems, where it says the initial date, as well as the projected retirement date.

Q. I guess what I'm really asking is if Sissiboo, Nictaux, and Paradise were pulled out separately, would it affect the depreciation rates, given that they have a different profile, perhaps, than Bear River and Lequille?

A. (MacIntosh) I may ask Mr. Wiedmayer to respond to that, in terms of the depreciation calculation.

A. (Wiedmayer) Yes, as Mr. MacIntosh has stated, all of the river systems that we've spoken about with regard to Bear River, Lequille, those river systems are all being depreciated through the year 2066. So the remaining lives for all of the river systems that would get aggregated into the Bear River system and the Lequille river system all have the same remaining lives. So we would recover the undepreciated investment at each of those hydro systems over their remaining lives, which would be the same period.

Q. Okay. So there's no impact on depreciation rates, then, by including Nictaux, and

Paradise, and Sissiboo in with those others?

A. (Wiedmayer) Correct.

Q. Okay. Thank you.

A. (Wiedmayer) You're welcome.

MR. MAHODY: Jeff, if could you call up Exhibit N-3 to Application, PDF page 44?

BY MR. MAHODY:

Q. Right at the top, it says:

> Decommissioning hydro assets is generally far more costly than refurbishing them, yet refurbishing may seem economically disproportionate to the output. This creates a difficult challenge for [Nova Scotia] Power's hydroelectric future.

I guess my question is -- and I supposes it relates -- or applies to let's exclude Tusket, and Mersey, and hydro for a minute. My question really applies to sort of those hydro systems that were kind of referenced in this quote as sort of refurbishment perhaps being economically disproportionate. If we continued to -- or Nova Scotia Power continues to exclude full decommissioning costs in rates. And an application comes before the Board for a small hydro system for refurbishment, and the options being considered are refurbishment or replacement with a new asset, be it wind or some other renewable. And in that analysis, when you do your economic analysis model, you would consider the costs of decommissioning included with the cost of the alternative; correct?

A. (MacIntosh) Yes, that's correct.

Q. So if Nova Scotia Power continues to exclude these decommissioning costs from rates in these sort of smaller hydro systems doesn't it just kind of keep it in a circle, in effect, that when a capital application comes before the Board for refurbishment of those assets you're always going to have this cycle where we don't have enough collected for decommissioning so those decommissioning costs have to be included in the economic analysis model for the alternative. So refurbishment will always be the preferred alterative, whereas if decommissioning costs are included up front when it comes time to do that analysis those costs are already collected and then we're only going to consider the cost of the new or the alternative source or generation source versus just refurbishment costs.

A. (Flemming) Mr. Murphy, I think the point I think that we'd like to raise in response to that is that if we were to bring forward such an application, our expectation is that the full cost of decommissioning would be considered in that economic analysis, regardless of what's been collected for the decommissioning.

Q. But wouldn't if it was already collected in rates then why would it need to be considered in that economic analysis? Certainly decommissioning of the refurbishment option at that time would be considered but that would be way out, right, say, call it 75 years out, a 100 years out for decommissioning. The NPV of that would be very low.

A. (Flemming) Sorry, Mr. Murphy,

you're saying why would we consider it in the case of if we've already collected the funds for it?

Q. If it's in rates -- if the full decommissioning costs are in rates you've collected it. So why would those costs need to be included in the economic analysis model? You've already collected those costs.

A. (MacIntosh) Yeah, so we would normally include that because it is a change to Nova Scotia Power's expenditures and therefore it's rate-based. So the way that Nova Scotia Power accounts for collected funds -- so we are collecting costs associated with decommissioning through the net salvage portion of our depreciation rate, and so we are building up a reserve or a liability, and so that is a reduction to Nova Scotia Power's rate base. If Nova Scotia Power is evaluating the actual expenditure of a portion of those funds, then that would have -- that would result in a reduction to the liability and an increase to net assets or Nova Scotia

Power's rate base. So we would always look at -- whether we've collected or not, we would always look at the actual expenditure of those funds as part of the evaluation.

Q. So how would that get factored into economic -- so you would be counting full decommissioning costs every time. When you submit an application for a small hydro system, you would include the decommissioning costs for that system at the time it's being decommissioned in that economic analysis model, even though the funds have already been collected?

A. (MacIntosh) That's exactly right, because if we've collected -- and so whether it's full decommissioning and partial decommissioning -- for the sake of this because we're proposing partial decommissioning we'll speak to partial decommissioning. But that's exactly right because it is a net change in the financial position of Nova Scotia Power. It's an expenditure of those funds. And if Nova Scotia Power doesn't utilize those funds for decommissioning of that assets Nova Scotia Power would still have that liability therefore lower Nova Scotia Power's rate base, reduce financing costs for Nova Scotia Power, or those funds if it's determined that those assets are never going to be decommissioned, those could be redirected towards either depreciation to recover the net book value of those assets or could be redirected to decommissioning costs associated with another asset.

Q. So if I use -- let me just use Tusket as an example, then. So if Tusket costs -- so full decommissioning costs were not included in rates for Tusket, and there's a capital application that's going to come to the Board eventually for an ATO, and the comparisons is going to be refurbishment of Tusket versus a brand-new asset, and the brand- new asset option is going to include those full decommissioning costs associated with the existing Tusket system; correct?

A. (MacIntosh) More likely partial decommissioning costs if we're using Tusket as an example.

Q. A partial decommissioning. It's still a big number. It's a big number.

A. (MacIntosh) Yes, sir.

Q. It makes the other alternative pretty difficult to get over the bar to be a viable option?

A. (MacIntosh) Yes, I agree with that premise. And that's the point we're making here, regardless of it's going to produce electricity or not there are substantial costs related to the civil works on that structures. So if it produces power, doesn't produce power, there are those costs associated with maintaining the safe operation of that asset.

Q. And if I understand Mr. Flemming right, if those partial decommissioning costs had been included in rates and already collected by Nova Scotia Power from ratepayers, those costs would still be considered in the analysis?

A. (MacIntosh) Yes, that's

absolutely correct, because Nova Scotia Power had we collected that already and then we go ahead and expend those funds that would be a significant increase for the company's rate base and therefore would need to be included in any financial analysis.

Q. Okay. I'll just go back to that exhibit I called up a little bit earlier.

MEMBER MURPHY: You don't have to call it up, Jeff.

BY MEMBER MURPHY:

Q. Because it's related to the tab you talked to -- or mentioned, Mr. Flemming, the second tab about the partial decommissioning costs, and those are confidential, so I won't bring them up. My question really was what's the basis for those costs?

A. (MacIntosh) Just so I understand, Mr. Murphy, you're referring to the site remediation, salvage, building structures, the component costs for partial decommissioning?

Q. That's right, yeah.

A. (MacIntosh) So in this GRA Application when we consider partial decommissioning we only included the assets to support the generation of the asset. So, for example, partial decommissioning the generator and the turbine only, and not including any of the other associated costs with the civil works to, say, remove the dam structures or the gates. That was ---

Q. I understand that.

A. (MacIntosh) Sorry.

Q. I'm asking where do those costs come from?

A. (MacIntosh) Yes, sir.

Q. Do they come from the Yates Report that was in the Hydro Asset Study?

A. (MacIntosh) Yes, sir. They came from the 2018 -- the scope of the work came from the Yates Report of 2018, and then those costs utilizing the escalation factors that we worked with Hatch to escalate those costs to 2024 dollars.

Q. Okay. So those costs are based on the Yates Report?

A. (MacIntosh) Correct.

Q. Inflated for -- I think the Yates Report was 2018. So inflated for six years or eight years.

A. (MacIntosh) That's correct.

Q. Can we get the Yates Report filed as an undertaking?

A. (MacIntosh) Yes, we can.

THE CHAIR: Undertaking U-10.

UNDERTAKING U-10 - To provide the Yates Report

MEMBER MURPHY: Jeff, do you still have that spreadsheet up with the columns hidden?

MR. GOODINE: Yes.

MEMBER MURPHY: Can you just put that on the screen for a sec?

Maybe we don’t even need it. I’ll just -- I’ll ask the question.

<u>BY MEMBER MURPHY:</u>

Q. As noted in the evidence and in the -- there's another tab in that spreadsheet related to Tusket and Nova Scotia Power's development, the Tusket costs, decommissioning costs, is a little more than what had been prepared in the H study, in the Hatch Study, from that hydro asset study.

There's a big gap in the difference between -- let's just talk about the partial decommissioning costs. There is a big gap in the partial decommissioning costs for Tusket that Nova Scotia Power has developed versus the partial decommissioning costs that the ACE Report developed.

I can call up the page if you'd like from the ACE Report to show Tusket, but it's a big gap. Do you agree?

A. (MacIntosh) Yes, sir. And I can

elaborate on why that is.

Q. Well, I -- just let me ask my question first and then ---

A. (MacIntosh) Sure.

Q. --- you'll see where it goes.

Given that there's a big gap in Tusket between the decommissioning costs that Nova Scotia Power says it's advanced further than all the other costs, how can the Board have any confidence that those other decommissioning costs that are based on the ACE Report are appropriate or accurate enough to include in depreciation rates?

A. (MacIntosh) Yes, it's a good point, Mr. Murphy. We did respond to this in IR-85, Part B that's in 27, Board IR, it's that same IR we had up, but we did recognize that the partial decommissioning costs that were included would be the minimum. So in the terms of Tusket, the scope of work for partial decommissioning was a different scope of work than we would have included in the scope of work for the partial decommissioning estimates of the other sites.

So in terms of Tusket, the Tusket partial decommissioning estimate includes civil works, so includes work with water retaining structures, dispatches associated. The partial decommissioning estimates that we've submitted for the GRA purposes have a much minimum -- a smaller scope of work.

So your point is that, yes, it is smaller based on the scope of work that we did include.

Q. So it'd be fair to say that the partial decommissioning costs for these other smaller assets would probably be a lot higher.

A. (MacIntosh) If there was the requirement to expand the scope of work beyond the generator and the turbine and the runner. So if you could just decommission the site and the powerhouse without having to expand the footprint in the civil structures, then it could be reasonable. But if there was a requirement to expand the scope like Tusket, then obviously the investment would be higher.

Q. Okay. One thing I noted in the ACE Report, could call it up if you want, but I don't think I have to, is that the ACE Report excluded any transmission cables, substations, and related transformer demolition and removal costs. Have those been included in the partial decommissioning costs included in the Depreciation Study?

A. (Flemming) Mr. Murphy, that is not included. So we have a separate net salvage rate for those type of assets, so your transmission substation type assets, and so it would be generally the costs observed through the retirement experience of those assets that would be built into the ---

Q. Okay. They're included elsewhere.

A. (Flemming) Correct.

Q. Okay. And what about taxes? I

don't think the H Report included taxes, or the archaeological study included taxes either.

A. (Flemming) Yeah. So Mr. Murphy, we -- the archaeological work is included, and we did submit the Boreas Report as well.

In terms of the taxes, that wouldn't be realized through depreciation and accretion expense, so we would have that somewhere else. So to the extent there was a tax impact, right, so say that the work was immediately deductible, that would be included in the financial analysis, but it would not be included in the depreciation or accretion expense.

Q. Okay. Okay, thank you

Do the partial decommissioning costs associated with the hydro assets, except for Tusket, Mersey, and Wreck Cove, do they include any rehabilitation costs to address any safety concerns or other issues associated with the dams and flowage structures and whatnot at the time you do the partial decommissioning?

[4:20:11] **A.** (MacIntosh) No, they wouldn't because of that scope of work that we did outline. So the scope of work would only be related to the generator and turbine proper, so it would not have any consideration for any of the other water management structures inside that scope of work.

Q. Would you expect that there'd be requirements for some repair and rehabilitation work to address some of the dams, spillways, and whatnot that are relatively aged?

A. (MacIntosh) In either scenario, if it's partial decommissioning or running the unit, you would have those same costs if you were going to run the unit or not run the unit. But in the partial decommissioning estimate we included here, we did not -- we did not have those associated costs.

Q. So those costs aren't included in the -- are not included in the Depreciation Study either.

A. (MacIntosh) That's correct.

Q. Okay, thank you

Would it be fair to say in the partial decommissioning scenario that there would be ongoing O&M costs and capital sustaining costs associated with any of the assets that are not decommissioned, particularly the dams, spillways, water retaining structures?

A. (Williams) Yes, even if there wasn't any generation coming from those sites, Nova Scotia Power, if they owned those assets were still required to maintain the safe operation of those assets and there would be an OM&G costs associated with it.

Q. And ongoing sustaining capital costs as well.

A. (Williams) Correct.

Q. And would you agree that once those assets are partially decommissioned they are no longer used and useful?

A. (Williams) Yes, I think generally speaking, sir, we would agree with that, and I think that gets to the point of where we're going with some of these hydro discussions, that there needs to be a broader discussion of how these are handled in the future, and if they are to be decommissioned whose responsibility ultimately that would be both as in the decommissioning phase of them, but also after that in maintaining them.

So I would agree that there’s a -- an inconsistency, perhaps, with traditional or normal utility practice if those were to be partially decommissioned and retained as assets of the utility.

Q. Right. If they were no longer used and useful and there was any further costs, ongoing O&M costs, capital sustaining costs as a no longer used and useful asset, any of those costs would typically be the responsibility of Nova Scotia Power and shareholders. Correct?

A. (Williams) And that's why I say I think traditionally our normal course, but I think there would need to be a recognition that those assets are not the same as -- and this is the discussion I think mainly with some of the larger assets, where if those structures were to be retained whose responsibility ought those to be. It's not the same as a generation asset in the middle of a field where you just reclaim it and it becomes brownfield and you can walk away from it, or sell the land, it's different than that. I think there would need to be a broader discussion of how those assets were handled.

Q. So you're suggesting that perhaps ratepayers should be on the hook for some costs associated with assets that they get absolutely no benefit from.

A. (Williams) So I wouldn't put it like that, sir, but that probably doesn't surprise you. I think in that scenario there would be a benefit to ratepayers, which is we would be doing something that, you know, otherwise if we fully decommissioned it, the partial decommissioning would be a lower cost to customers. So there would be a benefit to customers, but not in the sense of it's providing a service to customers, but the benefit would be there.

And I think when I say, you know, a broader discussion, I think it's a broader discussion within the province of how those would be handled if we were in a position where we were partially decommissioning assets, and to your point, which is a good point, no longer producing electricity or providing a traditional utility function, but there would be a benefit.

Q. Okay. That kind of brings me to my next question. In response to Board IR-85, PDF page 446...

MEMBER MURPHY: Maybe Jeff, you can bring it up.

BY MEMBER MURPHY:

Q. While Jeff is bringing it up, I'll just read it out. Nova Scotia Power states, in making the various proposals it has for the decommissioning costs that are included in the

Depreciation Study:

> ...[Nova Scotia] Power has initiated the broader discussions that is necessary to arrive at a future approach for these assets that considers and takes into account all stakeholders and their perspectives.

And then it goes on. My question is, can you describe for me briefly what you envision as part of that process and when you expect it to be complete?

A. (Williams) I think difficult for me to say when it would be complete at this point. I think -- I really think we're in the early stages of that, and I think this process in raising these issues is the initiation of the first steps towards that broader discussion. I think it needs to involve a broad group of stakeholders within the province. Certainly when I say stakeholders I mean those in this room, but also outside of the room, from a government perspective, from an environmental perspective, from a community perspective. So there's a number of different voices that I think need to be heard as part of that broader discussion. And our vision certainly would be that that involves all of those parties. And I would certainly include our Mi'kmaw partners as part of that as well.

Q. Would you expect it to be complete in advance of the next GRA?

A. (Williams) I would hope that we would have a better sense of things before next year. Because of the broad nature of that discussion, I don’t think I can provide a reasonable expectation of when it would be complete, just because there’s so many other perspectives that would need to be part of that.

Q. Okay. Thank you.

Just to follow up on a question that Mr. Mahody asked a little bit earlier, and I think, Mr. Flemming, you had answered it, and it related to the eight points part of the Consensus Agreement, where, you know, contingency was removed from decommissioning cost, inflation, and a number of different items. And you referenced the response to Board IR-87(c) that showed the impact on revenue requirements. Do you recall that?

A. (Flemming) Yes, I do.

Q. My question is, I wonder if you could just tell me, for the first three items, I think the response to the IR indicated that by making those changes, there was a 10.6 million reduction in depreciation expense in 2026 and -- sorry; in revenue requirements in 2026, and 11.7 million in 2027. Can you give me a rough sense of what impact that would have on the average rate increase if those were not included?

A. (Flemming) Yes. So the -- you're saying if we -- since we've removed those, since we've removed these costs from our depreciation expense, what is the impact and what is the overall rate of ---

Q. Yeah, if those weren't removed.

A. (Flemming) If they weren't removed. And you're speaking to just the first three items, the first three?

Q. But my next question was going to be all eight, so...

A. (Flemming) Okay. So -- and I'm always hesitant because there's usually tax impacts associated with this, and the -- so I'll speak to it on a pretax basis. So on a pretax basis, I would say you're looking at about a 0.5 percent one time rate change as a result of removing those.

Q. The first three items or all eight?

A. (Flemming) The first three items.

Q. Okay. Now ---

A. (Flemming) And then looking at a -- looking at the total of all eight, it would be approximately a 1 percent one time rate impact.

Q. Okay. Thank you.

Okay. Just a few more. And these are probably for Mr. Wiedmayer. Good afternoon, sir.

A. (Wiedmayer) Good afternoon.

Q. We can call these up if you want, Mr. Wiedmayer, but in Mr. Madsen's evidence, he filed a couple of depreciation studies that were recently completed by Gannett Fleming. One was for the Maritime -- one was for Maritime Electric, and another one was for Newfoundland Power. Are you familiar with those?

[4:30:02] **A.** (Wiedmayer) Yes, I am.

Q. Okay. When I looked at the Maritime Electric Depreciation Study that was completed by Gannett Fleming, it appears to me that it used the ALG procedure. Is that correct?

A. (Wiedmayer) Yes, that is correct.

Q. And I'll read a line from that. If you'd like me to call it up, I can, but I'll read a line from PDF page 13 of that study. It says:

> The straight-line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America.

My question -- my first question is why did you use the ALG procedure for Maritime Electric?

A. (Wiedmayer) The Average Life Group procedure was the procedure that was used historically throughout the history of PEI, and the company didn't want to change the procedure, and it hadn't been accepted by their regulatory board.

Q. Okay. And in the Newfoundland Depreciation Study, again that was completed by Gannett Fleming, you use the ELG procedure; correct?

A. (Wiedmayer) Yes, that's correct.

Q. And is the reason for using the ELG procedure in that particular Depreciation Study the same reason that you just gave for Maritime Electric? Was that the -- it was used by the company previously?

A. (Wiedmayer) Well, I would say Equal Life Group procedure, in discussions with my colleagues and other depreciation experts, including Professor Robley Winfrey, who developed the IOS survivor curves, he stated that the Equal Life Group procedure, which he called unit summation, was the only mathematically correct depreciation calculation procedure. So in jurisdictions that are receptive and utilize the Equal Life Group procedure, that is the one that I would recommend.

Q. Okay.

A. (Wiedmayer) And it has, in Newfoundland, similar to Nova Scotia, a long history of use, having been utilized for over 30 years in both provinces.

Q. Okay. Thank you.

Mr. Wiedmayer, are you aware of any utilities, North American utilities, that have used the ELG procedure and switched to the ALG procedure, or vice versa?

A. (Wiedmayer) Yes, I am aware. Yes.

Q. Which way; ALG to ELG?

A. (Wiedmayer) Both.

Q. Both?

A. (Wiedmayer) Both ways. Yeah, I -- in recent years, Equal Life Group procedure has become more of interest in states, in the United States where we also have a requirement by, let's say, 2045 to end all fossil use, whether it's a gas utility or an electric utility that uses fossil fuel. So Equal Life Group is becoming a procedure that is -- regulatory boards are much more interested in, in terms of understanding how do we recover all of these costs by 2045 or 2050 in a timely manner that promotes, you know, fairness to both the customer and the utility, and minimizes rate shock to the customer? So the Equal Life Group procedure is one of those methodologies that actually matches the consumption of the service value of the asset better than the Average Life Group, which just uses one broad average service life to depreciate a group of assets that have a variety of service life expectations. So in New York, Colorado, Massachusetts, California, other states that have looked into using Equal Life Group procedure for some of these utility proceedings, particularly in the gas industry.

Q. Okay. Thank you.

A. (Wiedmayer) Yeah. And, you know, to be fair, they're -- I am aware of Kentucky that switched from Equal Life Group procedure to the Average Life Group procedure in the last 10 years primarily because the Equal Life Group procedure was only utilized by one or two utilities in that state and it only had recently been adopted in the early 2000 -- 2005 or thereabout, and it got reversed, you know, 10, 15 years later.

Q. Okay. Appreciate that. Thank you, Mr. Wiedmayer.

A. (Wiedmayer) You're welcome.

Q. Another question for you just as it relates to peer analysis and completing these depreciation studies. In Mr. Madsen's evidence on PDF page 61 he states in his opinion peer analysis is critical in the case of Nova Scotia Power because of its reliance on simulated plant data, and this is because pure data would be largely based on his experience based on actual age data for the same assets.

I think in one of Mr. Madsen's IR's to you he asked about the peer analysis you did in response to Mr. Madsen's IR-13, Exhibit N-31, you provided an attachment that listed a number of utilities that you sort of compared to, but you said that that particular attachment contains industry database reviewed as part of a Depreciation Study. The database was used to assess general industry experience and trends to assist in developing service life and net salvage estimates for Nova Scotia Power. And then you go on to say no specific peer utilities were selected or analyzed individually. I'm just curious why you chose to look at industry group sort of more broadly rather than looking specific peer utilities.

A. (Wiedmayer) Okay, Mr. Murphy, that's a fair question.

The first step when we perform a Depreciation Study is we try to make a forecast for the service life of the underlying group of assets within each of these property accounts. So the first tool that we generally look to is the company's actual retirement experience. So that generally becomes the statistical foundation for the service life forecast is the company's actual experience. And then once I have determined what -- how long these assets have lived from a historical basis, I sit down and interview people in the engineering department, like Mr. MacIntosh and his team, and we kind of try and get an understanding of the retirement causes and how those retirement causes will apply in the future; you know, will they apply in the future to the same degree and magnitude based upon perhaps there may be some changes in technology or changes in material, or the company has, you know, changes in plan where, you know, perhaps they use a different material in the future than they're using today.

So that primarily helps form the basis for the service life estimate is the company's own actual experience, and then the input from the engineering department at Nova Scotia Power who is responsible for operating these assets, maintaining these assets, and ultimately the replacement of these assets. So they're the most familiar with these assets than anyone.

And then the way that we use industry data is really more of as a reasonableness check. Like, if I were to look at Nova Scotia's data for their line transformers and their line transformers based upon historical information was to say Nova Scotia Power line transformers only live 20 years when everyone else in the industry lasted 30 to 40 years, I would then follow up with Mr. MacIntosh and his team to find out, hey, how come the historical indications for line transformers at Nova Scotia Power is so short or so low. And a lot of times there could be some reasons for that; climate and your general coastal environments of Nova Scotia make your province more unique than a similar electric utility, let's say, in Manitoba.

So the peer data that we use or the industry data that we use, as I mentioned, is more of a reasonableness check to just make sure that we're inside the bounds of what is reasonable, what is used by other utilities. We don't use it as a substitution for the actual company's historical retirement experience which stretches back to the 1940s.

Q. Okay. In this case, did you make any adjustments to your depreciation estimates based on that industry comparison?

A. (Wiedmayer) Well, I brought up line transformers, and that does kind of have an interesting story, in the sense that the line transformers, I've estimated a 35 your average service life for Nova Scotia Power up from 30 years that we estimated previously.

And the reason for the increase was

not really supported by the historical data in the sense that the historical data indicated lives less than 30 years, significantly less than 30 years, because primarily those line transformers, the steel tanks associated with those line transformers that were put in, you know, a generation or two ago would corrode in your area faster than other areas. I don’t think that would come to a shock or a surprise to many in your province to know that, you know, rust and corrosion on steel is something that is experienced, not just on line transformers but other products made of steel or metal in your province.

And the company in the past, let’s say, 25 or more years have switched over from using mild steel tanks to a stainless steel tank, which is much higher resistance to rust and corrosion, so those tanks on the line transformers are lasting longer than they historically have. And I would say that that is, you know, one where Nova Scotia Power’s service life indications were outside the typical bound for other utilities, but with Mr. MacIntosh's input and his explanation of the company switching to stainless tank -- stainless steel tanks, we have an expectation that the service life for these line transformers will start to lengthen, and we've lengthened that service life accordingly.

Q. Okay. Thank you.

This is my last question. It's related to asset service lives and retirement dates. And in Mr. Madsen's evidence he referenced a number of your curves, I suppose, and how they fit with the data, the actual retirement data. And there was one in particular where it was related to transmission poles and fixtures, and Mr. Madsen had recommended a 50-R2.5 curve, and you have a 45-R1.5. And when you look at the curve -- I could call it up. When you look at the curve Mr. Madsen suggests that beyond year 30.5 the data doesn't fit very well, and that's part of the reason I think why he's suggesting a different curve. I can call the curve up if you want. But it does look like ---

A. (Wiedmayer) Yes, I would like to see that, because that is a good example of one that I think we should look at.

Q. Okay. It's -- Jeff, it's Exhibit N-34, PDF page 83.

MEMBER MURPHY: And Mr. Madsen made the same comment, Mr. Wiedmayer, this particular curve is just for transmission poles and fixtures, but he also made similar comments related to some of the other asset groups where the curves that you suggested don't fit that well.

In this particular case when I look at the curve it does look to me that it's not a great fit after year 30 or so. So my question was, you know, in this particular case, why do you think that 45-R1.5 is better than the one that Mr. Madsen suggested?

A. (Wiedmayer) Okay. Yeah, so here's a really good example, in the sense that the historical data is represented by those squares, black squares on the chart. So Nova Scotia's historical retirement experience indicates, when I look at this chart -- I know not everybody in the room is a depreciation expert, but what it indicates to me that the 45-year average service life indicated by that smooth black line is above or to the right of the black squares. So really the best fit IOWA types or R curve for this account probably is more like a 41- or a 42-year average service life from a historical basis.

So I had in the previous study recommended a 47-year average service life. However, Nova Scotia with, I think, tropical storms becoming more and more prevalent and some other reasons for earlier retirements, your actual retirement experience is indicating shorter lives than what I have proposed. Mr. Madsen's 50-year average service life would be even further above and to the right of my 45-R-1.5. So Mr. Madsen's 50-year recommendation is based, I would suspect, purely on industry data and judgment and not based on the company's actual retirement experience, which is a shorter life -- an even shorter life than what I've recommended.

Q. So in your opinion I guess, from what I'm hearing, the curves that are recommended by -- in this particular case anyway, the curve recommended by Mr. Madsen would be even a worse fit to that actual data; correct?

A. (Wiedmayer) Correct. That's exactly correct, yes.

Q. Okay, thank you.

MEMBER MURPHY: Those are all my questions, Mr. Chair.

THE CHAIR: I don't think I'm going to be that long, but given the time of day long enough, and I may actually be shorter if we break and come back in the morning, and I think that's my preference.

So we'll break now for the day -- we still have days to go anyway -- and reconvene at 9 o'clock in the morning.

Thank you.

--- Upon adjourning at 4:48 p.m.

CERTIFICATE OF COURT TRANSCRIBER

I, Patricia Cantle, hereby certify that I have transcribed the foregoing, and it is a true and accurate transcript of the evidence given in this matter, M12451.

Patricia Cantle
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Halifax, Nova Scotia
Thursday, January 8, 2026