M12661

NOVA SCOTIA ENERGY BOARD

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

- and -

IN THE MATTER OF: **AN APPLICATION by NOVA SCOTIA POWER INCORPORATED** for approval of an Extra Large Industrial Dispatchable Above-the-Line Tariff applicable to Port Hawkesbury Paper

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TRANSCRIPT

HEARD BEFORE: Mr. Stephen T. McGrath, K.C. Chair
Mr. Richard J. Melanson, LLB, Member

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

DATE HEARD: Tuesday, September 22, 2026

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Halifax, Nova Scotia

--- Upon commencing on Tuesday, September 22, 2024 at 10:00 a.m.

THE CHAIR: Good morning, everyone.

I just want to note for the record that the corrections to evidence that Nova Scotia Power filed, the revised version, has been filed as Exhibit N-48 in the proceeding.

Are there any other preliminary matters any of the parties wish to raise before we begin?

MR. MacDOUGALL: Yes, Mr. Chair. One.

Mr. Fitzhenry is here from Missouri, from BAI, and because the cross-examination of the NSPI panel has continued into today, just for timing purposes, we would propose to put up the BAI panel before the Port Hawkesbury Paper panel, which is just out of order, but we had said in prior communications to the Board, just to try and make sure we can get Mr. Fitzhenry done today.

THE CHAIR: Okay. Thank you, Mr.

MacDougall.

Anything else?

Okay. I think where we left off, we were up to Board counsel for cross-examination. I didn't miss anyone?

Okay, Mr. Mahody.

MR. MAHODY: Thank you, Mr. Chair.

MICHAEL WILLETT, Previously Affirmed:

ERIC FERGUSON, Previously Affirmed:

CRAIG MOWATT, Previously Affirmed:

DAVID STANFORD, Previously Affirmed:

CROSS-EXAMINATION BY MR. MAHODY

Q. Panel, I'm going to start with just a couple of follow-ups to some of the questioning from yesterday, and the first area is regarding the energy charge.

And Mr. Ferguson, I thought I heard you say late in the day yesterday that approximately 20 percent of the energy charge is recovery of fixed costs. Did I hear that correctly?

A. (Ferguson) That was my estimate, yes, just heavy on the "approximately". But it's just really the significant majority of it is fuel, with some allocation to fixed costs.

Q. Okay. But Nova Scotia Power acknowledges that PHP load, net of Goose Harbour output,

could be significantly lower than is reflected in the GRA basis for the energy charge; correct?

(SHORT PAUSE)

MR. FERGUSON: Sorry, Mr. Mahody. Could you just repeat the question? I'll try to give you a quicker answer.

BY MR. MAHODY:

Q. NSP acknowledges that PHP load, net of Goose Harbour output, could be significantly lower than reflected in the GRA basis for the energy charge.

A. (Mowatt) So Mr. Mahody, I think the question surrounds how significantly different the wind forecast could be compared to the GRA. Am I pointing in the right direction for you?

Q. Yes.

A. (Mowatt) So the wind forecast utilized in the GRA was approximately 500 GWh. I think that there's been evidence filed that would indicate that a P50 forecast would have been significantly higher.

Would it be hundreds of GWh different? No. Could it be tens of GWh different? Possibly, overall, compared to the P90 forecasts that we have.

PHP's load will be whatever it actually is in that period of time, but the wind forecast itself shouldn't be as significantly changed as might have been indicated in some of the evidence.

Am I approaching the right context for you?

Q. Well, Mr. Mowatt, the lower net PHP load is going to result in less fixed-cost recovery than was estimated. Is that correct?

A. (Ferguson) If the load is lower than forecast, yes, less fixed-cost recovery.

Q. Okay. And who, Mr. Ferguson, would be paying for those fixed costs that are not recovered from PHP?

A. (Ferguson) So we have a deferral that allows for differentials between what was assumed in

the GRA and what unfolded through this proceeding to accrue to it. With respect to material changes in wind forecast or wind results, I'd expect that to flow to the deferral.

Q. But just take me one step beyond that, Mr. Ferguson, about the recovery of those costs, albeit the deferral mechanism you've identified. But the customers who are paying those costs flowing through the deferral are which customers?

A. (Willett) So that would be for a future process where that deferral would be brought to the Board for the appropriate allocation to customers.

Q. And Mr. Willett, is it Nova Scotia Power's position that those costs would be allocated among all customers?

A. (Willett) That would be the expectation, that all FAM customers.

Q. The next area, just for clarification, is the value of RECs from Goose Harbour.

And during cross-examination by PHP's counsel yesterday, it was suggested that the value of the renewable attributes of Goose Harbour would accrue to Nova Scotia Power. Do you recall that?

A. (Mowatt) I do.

Q. And during that discussion, it was suggested and confirmed, I believe, by you, Mr. Mowatt, that the value of the environmental attributes could reach almost $22 per megawatt hour with further annual escalation thereafter.

A. (Mowatt) According to the Green Choice PPA that was presented, yes.

Q. Now, Mr. Mowatt, are you suggesting that the value of a renewable energy credit from a provincial renewable energy resource is $22 per megawatt hour?

A. (Mowatt) Renewable energy credits currently would have to be monetized outside of Nova Scotia. We would have to be able to sell a renewable-

based product into a neighbouring jurisdiction such as ISO New England to be able to monetize that currently.

How a REC market unfolds in the future, that could dictate that future process or that future pricing process, but as it stands right now, the only access that we'd have to monetizing any form of REC currently would be to either transact bilaterally with a third party or to sell it to a neighbouring jurisdiction.

Q. But Nova Scotia Power has been purchasing a substantial volume of renewable energy credits in support of the Renewable Energy Standard, hasn't it

A. (Mowatt) We've purchased somewhere in the neighbourhood of -- I don't have the exact number, but 150,000-megawatt hour equivalent of RECs, or some neighbourhood of that in the last two years to achieve the RES standard.

Q. But my understanding is that the price that Nova Scotia Power has been paying for those

RECs in the range of $2 to $2.50.

A. (Mowatt) That's correct, on those RECs.

Q. And if so, Mr. Mowatt, what is the -- what's your proposition for relying on the $22 megawatt per hour [*sic*] price that was referred to in testimony yesterday?

A. (Mowatt) Mr. Mahody, Nova Scotia Power isn't relying on that number. It was simply commentary on the price that was associated with the PPA that was brought up at that time.

Q. But the price that a REC market driven right now is -- your recent experience there is in the range of $2.25.

A. (Mowatt) I want to provide just a little bit of context on the REC market itself.

So there are a number of classes of RECs. The RECs that I was speaking to monetizing in another jurisdiction could be classified as a Class 1 REC,

which is associated with wind renewable generation. There are multiple classes of RECs that have varying prices associated with it to meet different renewable standard policies.

Q. And are you able, Mr. Mowatt, to -- then the RECs that you have been purchasing in the range of $2.25, are they comparable to the RECs that are attributable to Goose Harbour and, if not, how are they not?

A. (Mowatt) I only hesitate because we're going a little far afield from my expertise in terms of what each REC class stands for.

The REC class that Nova Scotia Power could currently monetize by selling wind in the example that I gave is a Class 1 REC and it's associated with that specific renewable type of generation. The RECs that you're referring to are slightly different. They're detached from a megawatt, necessarily sometimes, but we do receive those megawatts throughout the year and then

they're bundled with that product after the fact.

The necessary type of monetization would be determined by how that REC is delivered and how the RPS standard is written out such that that would apply.

I'm sorry. Probably went a little too far astray on that, so if you want to clarify that, I would be appreciative of that.

Q. I'm just trying to understand for the purposes of the record that if the reference has been made to a substantially higher price, the $22 price per megawatt hour, and we have evidence of Nova Scotia Power -- and there's direct evidence of this in the recent FAM Audit Report where substantial volume of RECs have been purchased at an orders of magnitude lower price than what was referred to in the testimony yesterday. And I'm trying to get an understanding for the record as to how the Board should be looking at that issue.

A. (Mowatt) I think it's important

to note that there is a difference between the RECs that you've referenced that we've purchased, which are attached to an import from a neighbouring jurisdiction, compared to a REC that is attached to a wind facility in the jurisdiction.

The REC that you reference is -- one of the benefits of it and one of the reasons why it's priced the way that it is is because not every megawatt imported assumes the green attribute, so it's an after-the-fact consideration.

There could be something along the PPA terms that you're referencing for the pricing that was talked about today where there is a natural REC value associated with it, given the fact that it's generated in-province attached to a facility in-province. Beyond that, I wouldn't want to characterize too many differences between the two of them.

Q. You mentioned, Mr. Mowatt, that we may be approaching your -- the extent of your

knowledge, your direct knowledge, in relation to that topic.

Would -- by way of an undertaking, could you give a -- could Nova Scotia Power provide a more full response to that inquiry as to the -- any differences between the RECs that Nova Scotia has been purchasing and the ones that are referred to in testimony yesterday?

A. (Mowatt) Yes, I think so. Yes.

THE CHAIR: I'm sorry, Mr. Mahody. Could you just restate the exact question that you want responded to in the undertaking?

MR. MAHODY: Sure. Nova Scotia Power would be providing an explanation of the differences between the RECs purchased by Nova Scotia Power as referred to in the FAM Audit and the RECs that were referred to in testimony yesterday from the Goose Harbour PPA.

THE CHAIR: Thank you.

That will be Undertaking U-11.

Undertaking U-11 - To explain the difference between the RECs purchased by NSP as referred to in the FAM Audit and RECs referred to from the Goose Harbour PPA

BY MR. MAHODY:

Q. Another area of clarification is about forward replacement cost methodology.

And yesterday I had understood Nova Scotia Power, when they were asked about why forward replacement costs for fuel would be used in the year-end calculation -- the DR credit that the panel stated the use of those forward replacement costs would be important to ensure that the port ops run against PHP's customer, the CBL, would be -- use the same price that's used in port ops. Did I get that correct, Mr. Mowatt?

A. (Mowatt) Yes.

Q. Now, previously Nova Scotia Power

has been critical of using forward replacement costs to determine after-the-fact valuation of load-shifting benefits. Is that correct?

A. (Mowatt) After you specifically referring to the ELIADC?

Q. Yes.

A. (Mowatt) Yes.

Q. Okay. And let me just take you to a reference because I'd like to get you to comment on what differences may exist.

MR. MAHODY: Mr. Norwood, I had sent through an ELIADC Report that I'd like to call up, if we could.

BY MR. MAHODY:

Q. And I believe this is a letter from March of 2023, Mr. Mowatt. We'll get it up.

Yes. So March 1st, 2023, a letter regarding the 2022 annual report.

You're familiar with this document,

Mr. Mowatt, or you would have been at the time it was created?

A. (Mowatt) Yeah.

MR. MAHODY: And so my reference for you, if we could just scroll down, Mr. Norwood, onto the next page.

BY MR. MAHODY:

Q. Okay. I've highlighted -- my highlighting, not yours -- not NSP's, Mr. Mowatt -- there's a section here that's highlighted.

> As further noted in the FAM Q3 report and repeated in the FAM Q4 report, 'While forward replacement fuel pricing is used in this report, NSPI has also been calculating the cost to serve PHP at a more granular level based on actual fuel consumption excluding financial hedges. It has been found that the use of forward replacement fuel pricing in 2022 is not representative of, and overstates the cost of the actual fuel consumed, due to previously mentioned unprecedented fuel volatility.

So just in light of that, Mr. Mowatt, I just wanted to give you an opportunity to comment on whether or not the reliance on those -- on that data

moving forward presents the same risks of overstating and, if not, why it does not.

A. (Mowatt) Thank you for the question.

I think this question highlights the difference -- one of the main differences between the ELID Tariff and the ELIADC. It's important to note that under the ELIADC, PHP was being costed out for their entire fuel consumption based on the methodology you referenced. Under the ELID Tariff, it's moving to an above-the-line cost structure where the majority of its costs will be priced as an embedded cost function. And Mr. Ferguson can interject if I get any of this wrong.

The important part to understand here is we're only pricing the dispatchable rider calculation, which is a very small portion, relatively small portion, of the total credit -- or of the total cost associated with PHP using the replacement cost methodology.

The methodology itself is derived to

isolate solely load-shifting benefits of PHP. To do that accurately, one needs to use the same pricing methodology in both the actual load profile provided by -- or at the end of the year, which PHP actually ran, and comparing that to the customer baseline or the levelized load profile.

The pricing that is used, it represents the opportunity costs on the system of running each fuel type, so in order to really capture the benefit of load-shifting, that replacement cost methodology is the appropriate one to use.

Another function that's beneficial of using the replacement cost methodology is that an accounting cost methodology would smooth out pricing, given the fact that you don't -- you might not have price variations throughout a day. It would be a same price for gas. It would be an average or weighted average cost. Whereas replacement cost methodology is the opportunity cost to Nova Scotia Power for dispatch during that day.

So it is influencing the dispatch decision behaviour of actually shifting the load.

I'm happy to take any follow-up questions from that because I know that can be a lot in a very short answer.

Q. The volatility that was being referred to in the report in front of you from 2022, that volatility has been present in the years since 2022 as well?

A. (Mowatt) General -- if you had have asked me that up till March this year, I would have said, yes, it's been more muted. There has been some volatility, not quite to the extent of 2022. But that volatility that you're referencing here would be present in both scenarios that I've referred to, the actual dispatch as well as the levelized dispatch.

So that would indicate that dispatching PHP's costs under that difference would be comparing apples to apples.

We're not pricing out the entire cost -- oh, I'm sorry. We're not pricing out PHP's entire cost based on this methodology, just the load-shifting benefit.

Q. Okay. I'm going to return to that load-shifting benefit just a little bit later.

Okay. Could I next turn to operating procedures? I just have some questions regarding how NSP intends this to work. And I think by way of reference, if we could call up Exhibit N-6, which is Nova Scotia Power's responses to Industrial Group IRs. And page 1390.

MS. RUBIN: Mr. Chair, I'm sorry to interrupt my friend, but I'm wondering if that letter could be marked as an exhibit.

MR. MAHODY: Sure.

Mr. Chair, I think yesterday we did have some examples of where matters from other records were talked about -- referenced and not entered. I'm fine either way. I have it ready to be -- obviously I've got some highlighting, I suppose, on this so maybe, in

fairness, we'll mark it as an exhibit.

THE CHAIR: Okay. That will be Exhibit N-49.

--- EXHIBIT NO. N-49:

NSPI's letter from March 1, 2023

BY MR. MAHODY:

Q. All right. So we have in front of us page 1390 from Exhibit N-6. And this is the Dispatchable Rider Operating Procedures. The panel's familiar with this document?

A. (No recorded response.)

Q. Can you confirm that the operating procedures contemplate three schedules: first, a Monthly Demand Schedule; number 2, a Seven-Day Demand Schedule, and third, the Intra-Day Demand Schedule?

A. (Mowatt) Yes.

Q. And Nova Scotia Power will generate at least four Monthly Demand Schedules each year and may generate more if required.

A. (Mowatt) Yes.

Q. And you will -- Nova Scotia Power will generate a Seven-Day Demand Schedule on a daily basis.

A. (Mowatt) Yes.

Q. And on any given day, Nova Scotia Power must provide at least one Intra-Day Demand Schedule to PHP.

A. (Mowatt) Yes, but to be clear, there will probably be two, three -- depending on what's going on the system, that could be more.

Q. Yeah, but at least one.

A. (Mowatt) Correct.

Q. Okay. And when Nova Scotia Power produces that Intra-Day Demand Schedule, that schedule becomes the schedule that determines whether PHP has deviated from -- in its dispatch loading instructions -- from the dispatch loading instructions?

A. (Mowatt) I believe so, yes.

Q. And Mr. Mowatt, is it the case that there would -- there will always be the intra-day schedule or will there ever be the need to rely on the Seven-Day Demand Schedule to determine the dispatch loading instructions?

A. (Mowatt) No, I can't foresee it for a circumstance that there wouldn't be an -- at least one intra-day schedule.

Q. When PHP deviates from the final schedule, the cost of that deviation will not be tracked.

A. (Mowatt) Correct.

Q. But you do plan on tracking the deviations themselves through the use of the cause codes.

A. (Mowatt) Correct.

Q. And what's the purpose of doing that, Mr. Mowatt? If, at the end of the tariff year, the method of reconciliation involves taking PHP's load as given and then levelizing and rerunning port ops, what's the purpose of tracking those deviations by cause codes?

A. (Mowatt) I think it provides parties, both Nova Scotia Power, PHP, and stakeholders, a sense of how Port Hawkesbury Paper and Nova Scotia Power -- apologies, more Port Hawkesbury Paper following those optimized schedules. It can help inform parties the degree to which the optimized profile was followed, and it will provide both parties a sense, in terms of where work might need to be done in either updating operating parameters or schedules to make the DR either more efficient or help with forecasting purposes as well.

Q. But any real-time tracking of deviations has no impact whatsoever on the calculation of the DR credit; correct?

A. (Mowatt) Correct. The DR credit is calculated based on the actual load compared to the levelized load.

Q. Cause Code 1 indicates PHP failure to meet dispatch due to equipment or process constraints.

Can you explain how a Cause Code 1 hour impacts or doesn't impact the calculation of the DR credit?

A. (Mowatt) I can, high level without using too many numbers. But I can foresee a scenario in which we're asking PHP to ramp up overnight due to a low-load, high-wind situation and then they could be in a situation where, mechanically, they can't actually run up due to some outage or unforeseen mechanism so, therefore, they can't meet that optimal schedule. We could be ramping them up 50, 60 megawatts, so that would be a Cause Code 1.

How that would work out in the DR benefit is that the -- depending on the load level that PHP is at may not be as high as the levelized load for that hour, at which point the levelized costing would come in lower than the actual costing of the actual hour.

Q. The reference to dispatching, is it fair to say, Mr. Mowatt, that dispatching is

predominantly dispatching down?

A. (Mowatt) I wouldn't say that, no.

Q. Okay. And so is it the case that Nova Scotia Power has looked under the exiting tariff, that you've looked and analyzed the number of times dispatch has occurred and that there is approximately an equal number of dispatches up as dispatches down?

A. (Mowatt) I wouldn't be able to speak to the detail of it. I do know, heuristically, that the benefit of PHP's dispatchability is the fact that it can come up and can come down to meet system requirements. So for instance, over the last number of days we could have had a high wind event, at which point PHP's ability to ramp up to absorb that wind to either save unit start so we can keep existing generation online to meet peak demand later that day or to be able to absorb more wind and maintain economic imports is a valuable part of the system.

Likewise, they could have ramped down

over the last number of days as the wind forecast comes off and generation -- resourcing becomes tight, so they would try to follow that wind profile to the best of their ability with their load.

Is that -- does that answer your question, Mr. Mahody?

Q. I'm trying to get a sense about whether or not Nova Scotia Power has empirically tracked dispatches up versus dispatches down in order to reach the conclusion that it is pretty much an equal split between the two -- has been pretty much an equal split between the two.

A. (Mowatt) I don't know, off of the top of my head, if that has been done empirically, as you stated. I wouldn't -- I can't think of a report or anything like that that I've seen that would have suggested that.

Q. But nonetheless, from the -- Nova Scotia Power's perspective, there has been value in the

ability to dispatch both up and dispatch down demonstrated to date.

A. (Mowatt) Absolutely, yes.

Q. Okay.

A. (Mowatt) Just to add on to that last statement, some of that is due to the increased amount of wind and intermittent generation that we have on. That flexibility that they provide does add significant benefit to the system, as I stated before, we're capture some of the wind sharping.

Q. And that value going forward is predicted by the company to increase because of the changes -- the ongoing changes to the system. Have I got that right?

A. (Mowatt) Certainly over the near term, yes. Yeah.

Q. And Mr. Mowatt, when you say, "Certainly over the near term," what is it? Is it during the transition it's of a certain level of value but then

that value would decrease when you reach a steady state? Tell me ---

A. (Mowatt) The reason why I say "near term" is when my group conducts forecasts, it's out generally to 2028. Anything beyond that would be a higher-level forecast without the detail.

So I can tell you that based on the forecasting that I've seen over that period of time, it's valuable. Anything beyond that would require more detailed forecasting than I've been through.

Q. Yes. So just that you've not looked beyond 2028. It's not that the value might -- that the value's going to change after that.

A. (Mowatt) Correct.

Q. Understood. Thank you.

Cause Code 2 from the operation procedures indicates:

> PHP-initiated request for a new dispatch level which Nova Scotia Power or [the System Operator] agrees to.

You see that in Cause Code 2?

A. (Mowatt) I do.

Q. Isn't it the case that the agreed-upon schedule would necessarily have a higher system cost?

A. (Mowatt) I wouldn't say "necessarily"; there can be multiple paths to optimality.

One of the -- one of the nuances to PHP's dispatch and the DR credit is that in a given hour it could look like a dispatch is not optimal but, over a period of a day or time, could be optimal. Because of different system conditions, constraints it's very difficult to look at a single hour and assess whether or not that's the right decision.

To your point on the specific cause code, I generally read this to be there's no system conditions that are impacted by reliability based on the decision. It may not be the most optimal decision at that time, but it doesn't necessarily mean that it's not an

optimal decision over a day or a period of time.

Does that make sense, Mr. Mahody?

Q. Mr. Mowatt, doesn't that engage on this issue of what, if any, price signals or data is being supplied? Because if Nova Scotia Power is providing the direction in the daily scheduled PHP without any of the pricing information, PHP is not going to know whether deviation would have a small system cost because it could, couldn't it?

I mean, the next -- the next optimal dispatch could just be slightly higher than the one that is optimal; correct?

A. (Mowatt) Correct. I think the nuance to this is that PHP and our marketing desk are in contact quite frequently and they do discuss when is an appropriate time to run. And it could be something to the fact that PHP has a requirement to run it that certain way and it's not impacting the system.

I would point to the fact that under

the ELID construct, the DR benefit flows solely to PHP. So if it isn't the most optimal dispatch at that time, they would be aware that they're just reducing the amount of that dispatchable rider benefit that they could see.

PHP's been dispatched by Nova Scotia Power for many years under the ELIADC and, prior to that, the LRT, so if they see a dispatch changing, they may not have a price signal, but they'd have a sense in terms of what the system is allowing for their load.

They may not see what unit is serving them, but they'd understand that if we're trying to turn them up, system costs must be easing or if we're trying to turn them down, system costs must be increasing.

To your exact point, if they're asking to go up a certain level, you're right, that could change their costs, that DR benefit that you suggested, but under the conversations that they'd have with the marketing desk and PHP's own awareness that they're receiving 100 percent of the DR benefit, they'd be making that economic choice

themselves.

Does that answer your question?

Q. Well, it does. But doesn't it raise this -- these discussions with the marketing desk, which I don't take issue from, from an operational perspective, but the tariff seems to describe a prescribed schedule is given to PHP. But is it that in addition to that schedule then there are these discussions which take place with the marketing desk? Does -- sorry; let me finish.

Does that result in the issuance of an updated Intra-Day Schedule, those discussions?

A. (Mowatt) The desk does talk to them frequently. To the extent that it would change the schedule would depend on what's going on with the system and how that -- and how PHP might be required to run that day.

I don't want to get into hypotheticals, but if the way that they want to run they

can be ran at, we might need to optimize the system for another schedule for that manner.

That does not mean that the DR benefit is going to calculate out to a positive behaviour based on that. What that -- all that shows is that the PHP ran higher. The ultimate DR benefit is always compared to that levelized load.

Does that ---

Q. So this Cause Code 2 hours, do they have any impact on the calculation of the DR credit?

A. (Mowatt) No.

Q. And Cause Code 3 is PHP's decision to vary from dispatch.

Does -- do hours impacted by Cause Code 3 have any impact on the calculation of the DR credit?

A. (Mowatt) They could. I can't get into specifics because it depends on the nature of how they ran, but I can foresee a circumstance where they're

asking to run when the system is generally more expensive for whatever reason, but generation is available for PHP to run higher. That would impact their DR benefit as compared to the CBL.

Q. And how would that impact the calculation of the DR credit?

A. (Mowatt) So in a given hour -- I'm going to use examples just because I think it's easier to talk about this using examples.

For instance, say PHP -- say Nova Scotia Power's requesting PHP to run at something like 70 megawatts. PHP wants to run at 100 megawatts for whatever reason. The system might be required to dispatch a more expensive gas unit to meet that, but we have the ability to actually satisfy that request. So they vary -- they run up.

Compared to the CBL level, that could be less economic than the CBL itself. If they were to run high enough, that could cause the cost to be higher in

that hour, just given the generation costs associated with that.

And if you need any more, I can try to clean that up.

Q. I don't know if I need any more, but I need it a little bit slower. So can you go back over it?

A. (Mowatt) Sure, sure.

Let's use round numbers because it's easier.

PHP -- Nova Scotia Power's requesting PHP to run at 100 megawatts. PHP decides to run at 130 megawatts, but there's no reliability concerns on the system. Nova Scotia Power can accommodate that by ramping up more expensive generation, whatever that is; gas, in this instance.

If, for instance, the CBL at the end of the year is calculated to be 125 megawatts for that hour, the fact that PHP ran at 130 megawatts at a higher

cost compared to the CBL at 125 megawatts at either the same cost or lower would result in that hour having a negative DR benefit.

And specifically for that hour. So I want to be very clear that the DR benefit on that hour would be lower. On the day it could be different, depending on how that dispatch shook out.

THE CHAIR: Mr. Mowatt, if there are a series of those events over the course of the year, in theory, could the annual DR credit calculation be negative overall?

MR. MOWATT: Mr. Chair, I think that would be a very -- I think that would be very difficult to do mathematically in terms of, like, eroding an entire DR benefit.

For instance, the way that I think about that is for the DR benefit to be negative, you'd have to see PHP running in ways that are absolutely contrary to the system, so they'd have to be running low

load when the wind is blowing, they'd have to be running very high when the system isn't able to do that. I don't know if you could get enough of those hours to erode that kind of a benefit.

It would certainly erode some of the benefit, but I couldn't -- I don't want to say that it would erode all of the benefit mathematically. I just -- I have a hard time seeing how that would shake out like that.

THE CHAIR: So theoretically possible, but unlikely?

MR. MOWATT: Very unlikely. I would say very, very low probability.

THE CHAIR: And if that happens, does the credit actually become a payment under the tariff?

MR. MOWATT: Yes.

BY MR. MAHODY:

Q. Could I turn to PHP's operating modes?

And can we begin by just getting an explanation from the panel about what an operating mode is?

A. (Mowatt) I'll try my best. I'm not on the marketing desk. I just understand it from PHP's point of view.

But an operating mode is typically designed as a megawatt range that they would operate in for a given set of their production.

Q. So you could have an operating mode that is operating between 90 and 110 megawatts, for instance?

A. (Mowatt) Something like that, yes.

Q. Okay. And the ELID Tariff as proposed protects PHP from being given dispatch instructions that violate the operating modes?

A. (Mowatt) The operating instructions are meant to ensure that PHP can follow

dispatch, so it would be in accordance to those operating modes.

Q. So -- but in the sequence of this, PHP as part of the process will specify an operating mode.

A. (Mowatt) Correct.

Q. Okay. And the tariff itself protects against PHP giving -- PHP being given dispatch instructions that are contrary to that operating mode.

A. (Mowatt) Yes.

Q. Okay. And the number of operating modes, as compared to the previous or the existing tariff, has been reduced from nine to seven. Is that correct?

A. (Mowatt) Yes.

Q. Why was that done?

A. (Mowatt) I don't want to speak for PHP's -- on PHP's behalf, but my understanding is that it's just more efficient for them to run under the OM-6

mode to meet their production schedules.

But again, I don't know the exact nuances around their decision-making.

Q. But Mr. Mowatt, isn't it the case that specifying fewer operating modes reduces the flexibility that's offered by the PHP load?

A. (Mowatt) You're correct, yes.

Q. Okay. Why did you agree to that?

A. (Mowatt) Well, if we were to call PHP under an operating mode that's higher that they're not going to run at, we're setting the system up for a megawatt level that it can't hit, and we have to plan for what can actually be done on the system.

PHP is a mechanical process. There are certain things that they can and can't do, so you have to respect that mechanical process and be able to plan around that accordingly.

Q. So whatever flexibility was given up moving from nine to seven operating modes, from Nova

Scotia Power's perspective it most appropriately addresses the operational constraints at PHP.

A. (Mowatt) Correct. And it should also be noted that, like, those higher operating modes that they had, they could only run at for limited periods of time. So although you are correct, it does reduce flexibility, it's not like we could run them at a significantly high megawatt level for a day or something.

There is a mechanical process behind that that will eventually limit that.

Q. And the operating procedures in the proposed tariff excuse PHP from complying with dispatch instructions for reasons of equipment failure?

A. (Mowatt) Yes. Similar with any generator that could have an equipment issue, it may not be able to run for a certain reason.

Q. But in the existing ADC Tariff, equipment failure is not specified as a reason to not dispatch according to instruction, is it?

A. (Mowatt) I'm sorry, Mr. Mahody, I don't know that off the top of my head.

Q. Perhaps you could accept an undertaking to review and compare the ELIADC Tariff with the proposed tariff, specifically in relation to equipment failure, and confirm whether or not the ELIADC Tariff specifically identifies equipment failure as an excuse to deviate and, if it doesn't, if you can explain why that change is being made.

A. (Mowatt) Yes.

THE CHAIR: That will be Undertaking U-12.

UNDERTAKING U-12 - To review and compare the ELIADC Tariff with the proposed tariff, specifically in relation to equipment failure and confirm whether the ELIADC Tariff specifically identifies equipment failure as an excuse to

deviate, and if it doesn't, explain why that change is being made

(SHORT PAUSE)

BY MR. MAHODY:

Q. Mr. Mowatt, the reconciliation at the end of the year that you referred to in relation to the DR credit, is it the case that that reconciliation has certain negative sides to it?

For instance, there's the time lag associated with doing an end-of-year calculation as opposed to doing the calculation at the time the deviation occurs. Do you agree with that?

A. (Mowatt) I understand the question. Again, I think it's important to understand that, as I mentioned before, a deviation in a specific hour is not indicative of an optimal dispatch, so by completing it at the end of the year, Nova Scotia Power can see not just load-shifting in a day, in a month, but

also seasonally as well -- or, sorry; monthly deviations, how PHP structures its load at the end of the year.

It's also important to note that, at the end of the year, the calculation uses PHP's total load for the year. That's required to take into account how PHP's load requirements would have been for that period of time so you're avoiding a forecast of any kind to calculate that.

You also need the end of the year to see how many days PHP was at house load or down in order to levelized out the CBL for that period of time to calculate out that levelized profile.

Q. Is there any discretion that's being applied by Nova Scotia Power in conducting that year-end differential calculation?

A. (Mowatt) I'd say Nova Scotia Power has access to all of the information that's required. We have the replacement cost, we have PHP's total load, we have the system conditions at that time.

The calculation itself is fairly straightforward. Even the levelizing of PHP's load to mimic that high load factor, that CBL profile, is a formulaic approach. We're using a random seed in order to ensure that there isn't personal bias or any kind of discretion associated with the randomized days to mimic an agnostic -- a customer agnostic to price movements on when they would take those down days.

So it is very much formulaic.

The access to information makes it such that Nova Scotia Power is the only party in a position do the calculation.

Does that make sense, Mr. Mahody?

Q. It does, so then back to my question.

What, if any, discretion is Nova Scotia Power utilizing when it's doing those calculations?

And if the answer's none, it's none.

A. (Mowatt) None that I can think

of.

Q. And your point regarding access to data is one that Nova Scotia Power would be in a position to be able to share all the data that underlies its calculation and anyone would be able to do the calculation because there's no discretion involved; it's just purely a mathematical exercise. Have I got that?

A. (Mowatt) Yeah. The sharing of the data becomes an issue just because of the volume of data. If one can think there's 80,760 hours in a year and every hour would have generated associated with every unit, it becomes a very large data exercise in terms of -- in terms of that. But the overall calculation itself would be straightforward.

I also want to note that we would be utilizing port ops, which is the software used for dispatch, to do the calculation, as that would be running the new dispatch associated with the levelized load as well.

Q. But if whosever's reviewing it has the capability to consume the amount of data that's involved and has the opportunity to consider port ops and the outcome of that, there's no reason why they shouldn't be able to replicate Nova Scotia Power's calculation without any discussions with Nova Scotia Power, for instance.

A. (Mowatt) Correct.

Q. Okay. Mr. Ferguson, just a couple questions regarding the demand determinant, and specifically the 65-megawatt figure.

First off, from a generation planning perspective, the non-firm portion of PHP's load is excluded from system firm peak; correct?

A. (Ferguson) Yes.

Q. But for transmission and distribution, it must be planned to meet the full peak load, including PHP's full load; correct?

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

Mr. Mahody.

Q. All right. Thank you, Mr. Stanford.

So now I think I'm back to you, Mr. Ferguson. The company -- the tariff proposes -- the cost of service proposes using the same 65-megawatt demand determinant for allocating both generation and transmission. Why is that when the planning assumptions are markedly different?

A. (Ferguson) The approach is in accordance with how we calculate and assign costs to the other classes, large industrial classes. We calculate the demand determinant for the large industrial class based on total forecast load and assign transmission and generation demand-related costs based on total load, firm and non-firm, of the class, and then we calculate the credit based on the forecast non-firm portion at peak. That's the same methodology here.

And of course, as discussed yesterday,

the credit is a generation credit because that's -- as Mr. Stanford said, that's the avoided cost opportunity generating capacity.

Q. Thank you.

Let me turn now to the actual 65-megawatt determinant that Nova Scotia Power has proposed. And you referred yesterday, Mr. Ferguson, to some long history, and dealing with this particular facility in Port Hawkesbury has a long history before the Board. You quickly get into names like Stutz and Rosenberg and Brockway.

And one of the elements of that history has traditionally been an amount of reliance that's placed on Nova Scotia Power as the expert operator of the system, no-one knowing the system better than Nova Scotia Power in its experience in operating it.

And it strikes me that on this billing determinant quantum number, the Board may well benefit from Nova Scotia Power's clear view of what a reasonable

billing determinant for that would be, and so I'd like to separate out for a moment the issues regarding the Settlement Agreement and what reliance could be placed on that. And not to subtract from any weight of those positions, but specifically on what is an appropriate billing determinant and whether or not the 65 megawatts is that or not. Do you have input in that regard, Mr. Ferguson, as to whether or not that is a reasonable number?

A. (Ferguson) In my view, it is a reasonable number. It recognizes that Port Hawkesbury Paper is likely to be dispatched below its average load at time of system peak, but it also allows for a more material contribution to be made by Port Hawkesbury Paper in accordance with their overall use of the transmission and generation system than would occur if you used their actual load when they're dispatched down to minimal levels.

As I mentioned yesterday, it happens

to be the average -- or approximately midpoint of what Mr. Bowman is recommending and PHP is recommending, so it's -- it is an unusual -- it is a challenge for this tariff. One class -- a class of one customer with highly volatile load for which we'll be trying to optimize costs and running them accordingly. But you have -- for this case, the judgment is -- are going to take into consideration, I expect, what the actual history is, load, but also consider what's the benefit, what's the use of this -- of the system overall by this load that has 800 GWh across the year, 300 after the wind's allowed for. What's the appropriate determinant that recognizes that significant use across the year?

And sorry, just to -- and I think the 65 is a good starting point. I expect it to be reviewed in future GRAs and refined, but I think it's a good place to start.

Q. And this may be unfair, but if there was no Settlement Agreement and if there was no

range being provided by PHP and by Mr. Bowman, would you still be recommending the 65 megawatt?

A. (Ferguson) I think that's really a case of we'd have to do more digging into accepted regulatory practice for dynamic loads like this and, really -- my conversation yesterday with the Industrial Group was really around how does the industry deal with loads of this type.

I think the -- I think the Intergroup commented on some of the challenges with cost allocation when you have customers that have such a high proportion of the load interruptible and it's as dynamic as Port Hawkesbury Paper will be, so I'd have to say it's an area that we'd want to consider further and consider accepted utility practice more than we have. We've relied largely on the Settlement Agreement terms, and you heard my earlier comments.

Q. It is September of 2026. There's a -- a rate offering seems to be needed.

Is it the company's position that for at least the 2027 period the 65 megawatts is an objective, reasonable approach for that period to then be revisited at a subsequent time?

A. (Ferguson) It is, yes. We propose to revisit it -- expect to revisit it as part of the next GRA.

MEMBER MELANSON: Can I just interject on that because I had some questions that I'll just follow on that?

Absent a Settlement Agreement, why would the 28-megawatt number that's calculated based on more recent information not be the correct number?

MR. FERGUSON: Well, for me it gets back to --

MEMBER MELANSON: Using the same methodologies that we've used as a template for the 65 megawatts.

MR. FERGUSON: Yes. Yeah, I -- that's

right. You could -- you could assume -- recent history is indicative of the determinative that should be used for demand determinant, but does 28, which is approximately a percent of peak load, fairly represent Port Hawkesbury Paper's usage of demand-related costs, generation and transmission?

For a load that is, again, of the magnitude of Port Hawkesbury Paper, I would submit it doesn't.

MEMBER MELANSON: Thank you.

BY MR. MAHODY:

Q. Can I turn next to the interruptible capacity that's available after dispatch?

And just as a starting point, and I think I heard confirmation of this yesterday, but Nova Scotia Power treats economic dispatch and reliability interruption as distinct services, but you would acknowledge that there's operational interplay between them. Is that correct?

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

Q. And Port Hawkesbury Paper's load above 8 megawatts can be reduced through economic dispatch, and it can also be subject to reliability interruption.

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

Q. And so if we assume PHP is at 120 megawatts and Nova Scotia Power economically dispatches it down to 50 megawatts, then the load remaining above the 8 megawatts is the 42 megawatts; correct?

A. (Ferguson) Yes, correct.

Q. And so Mr. Stanford, in that circumstance, the amount of load remaining available for additional reliability interruption can depend on how far PHP has already been economically dispatched.

A. (Stanford) It can, but I will just qualify that the benefit of the interruptible rider is related more so to the longer-term resource planning benefit. So the fact that Port Hawkesbury Paper's load,

the majority of which is interruptible, means that we do not have to plan to serve that load and build generation capacity to build -- to serve that load in long-term resource forecasting -- or pardon me, long-term resource planning.

Q. But it's all of PHP's load above its firm level that is not planned for, isn't it?

A. (Stanford) Yes, that is correct.

Q. And that's because of the dispatchability.

A. (Stanford) No, that's because that load is considered interruptible.

Q. Okay. But has Nova Scotia Power conducted any analysis -- historical analysis of PHP's load to determine what is available for additional interruption after dispatch has occurred?

A. (Stanford) Only the analysis that we presented as part of IR responses, which identified that, you know, in general, under most circumstances, PHP

-- during a system capacity shortfall event, PHP is most often -- has already been dispatched down under the Active Demand Control under the ELIADC Tariff and thus would have little to no load available -- essentially no load available to interrupt under the interruptible rider.

Yeah. I'd just like to add, Mr. Mahody, that it's not just -- you know, the ability to have access to this interruptible load is not just at periods during when we might have capacity shortfall, but -- so say, for example, if we had an unexpected generation or resource loss, PHP would likely be at a higher level and then, if we needed to access that load to help reduce system load to address the contingent loss, we would have access to do that under the interruptible rider.

Q. And Mr. Sanford, does the historical -- over the last six years, does it not demonstrate that the vast majority of requests to PHP have been to dispatch and so, from the reduction side, it's been to reduce your load -- direction to reduce its load

and with only one occurrence of a request to interrupt, isn't that indicative of the fact that the reduction of PHP's load is a result of dispatch as opposed to interruptibility?

A. (Sanford) As we've provided for previously, PHP, under the dispatchable rider, can choose to ride through and not respect those schedule changes, so the interruptible provisions of the interruptible rider provide the mechanism where the System Operator can bring them down for reliability reasons. If they fail to come down following a request for interruption, then they would be subject to significant penalties.

Q. And that difference is what Nova Scotia Power points to that, from a planning perspective, it's able to treat interruptibility as different from dispatch?

A. (Sanford) Yeah. From a long-term planning perspective, you know, when you look at the values stream from the two services, they're two separate

and distinct services. With respect to the interruptible rider, that means that the company doesn't have to build additional generation capacity to serve that load from a long-term planning perspective.

With respect to the DR rider, that's more about re-dispatching PHP to provide the most economic dispatch, so it's more about kind of the operational timeframe as opposed to the long-term planning timeframe.

Q. But is it also a consequence, from a planning perspective, of knowing that through the interruptibility provisions you can mandate with significant penalties if they don't follow those, whereas with the dispatch, the consequences are an ability to run through it?

A. (Stanford) Could you -- sorry. Could you repeat that question?

Q. Certainly.

So is it a material difference from Nova Scotia Power's planning perspective that

interruptibility comes with those significant penalties, that if you don't abide by a direction to interrupt, there's significant penalties versus the consequences for dispatch directions that aren't followed?

A. (Stanford) So it's two different planning exercises.

So with respect to the interruptible rider, you'd be planning -- you'd be doing more resource -- system resource planning on a longer-term basis. With respect to the dispatchable rider, you'd be planning within the operations timeframe looking at the economics of dispatching the system on a day ahead or intra-day basis, and then placing or dispatching PHP's load appropriately to ensure the most economic dispatch of PHP in concert with all the other generation resources available.

Q. Mr. Stanford, is it too simple to say that the dispatchability on its own means that Nova Scotia Power ignores PHP's load above its firm level,

ignores it when it's doing any planning exercise?

A. (Stanford) Can you clarify what you mean by "planning exercise"?

Q. Sure.

When it's planning for the delivery of its service, it ignores PHP's load above a certain level.

A. (Stanford) If you're referring to, like, long-term resource planning, then yes, that would be correct.

Q. Okay. So if...

A. (Stanford) So I'll just clarify here.

So if we're talking long-term planning, PHP's load is not included in the load forecast from a long-term generation resource planning perspective. If you're talking about kind of day-ahead planning, planning to serve the load the next day, then PHP's load would be planned to be served with generation on a day-ahead planning basis.

Q. And could you just ---

A. (Stanford) Can I just ask -- one sec.

(SHORT PAUSE)

BY MR. MAHODY:

Q. So Mr. Stanford, you don't plan for the PHP load, but on a day-ahead basis it is factored into your schedules.

A. (Stanford) Yes. And just to clarify, we don't plan for the capacity in the long-term resource planning for the PHP load, but you're correct, on a day-ahead basis, we do plan to serve them -- plan to serve what their energy needs are on a day-ahead basis.

Q. Okay. And the reason you do that is because of the terms of the tariff under which PHP is taking its service.

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

Q. But you don't analyze whether or not your -- the reduction associated with that planning

assumption is a result of interruptibility or the dispatchability.

A. (Stanford) No, we don't because they're two separate value streams. Yes. Two separate services.

Q. Two separate services addressing the same load.

A. (Stanford) Well, again I'd go back to -- yes, they're -- they're operating on the same load.

So for example, if, you know, in another -- another way of looking at it is we have other customer classes that are interruptible so, for example, a large industrial interruptible, and they -- that group of customers receives a credit, is passed a credit on their demand charge. And there are some years where we've had no interruptions, so it's really they're being compensated for the ability -- just to have the ability to interrupt them during times of system capacity shortfall.

Q. But none of those customers are dispatchable.

A. (Stanford) That is true. That's correct.

MEMBER MELANSON: Can I just follow up on that?

Is not the reason why you can eliminate anything that's above the firm capacity when you're doing long-term planning or you can't eliminate the dispatchability is because of the various standards and rules that tell you how much you can include for your capacity when you're looking at your planning reserves and that type of thing?

MR. STANFORD: Yes, that's correct, Mr. Melanson. There's an NPCC -- Northeast Power Coordinating Council standard that defines as part of your longer-term planning, you have to plan to serve your peak load plus a planning reserve margin.

MEMBER MELANSON: And what you can

include in your capacity for that purpose, you can exclude, I guess, the interruptibility component, but you can't exclude dispatchability. Is that right?

MR. STANFORD: You can -- you would include only load that's designated as firm load in the load forecast that goes into that exercise.

MEMBER MELANSON: Right. So the dispatchable load can't be included in that.

MR. STANFORD: If it was firm load that was dispatchable, then yes, you would include it because it would be -- it's more about the load being either firm or non-firm as opposed to being dispatchable or non-dispatchable.

MEMBER MELANSON: Okay.

BY MR. MAHODY:

Q. Mr. Mowatt, I'm gong to return to the dispatchable rider which are questions, perhaps, for you.

The dispatchable rider compares actual

system cost with an estimate of system cost assuming PHP had operated without dispatch at the prescribed high-load factor profile. Is that correct?

A. (Mowatt) I'll get you just to repeat that ---

Q. Certainly.

A. (Mowatt) --- one more time.

Q. The dispatchable rider compares actual system cost with an estimate of system cost assuming PHP had operated without dispatch at the prescribed high-load factor profile.

A. (Mowatt) Yes. To -- I just want to clarify the actual system cost is not an accounting-based cost but is a replacement cost methodology.

Q. The load that PHP would actually have taken in the absence of dispatch cannot be directly observed. Do you agree with me?

A. (Mowatt) It was not observed, correct.

Q. Okay. It was not observed. Is it that Nova Scotia Power has identified a mechanism of doing that that you could identify PHP's load that would have actually occurred, absent the dispatch?

A. (Mowatt) The methodology in which -- or the methodology in which Nova Scotia Power would develop that customer baseline is based on a functional formula in terms of how that levelized load could look if PHP was agnostic to prices and running at a levelized load.

Q. But Nova Scotia Power has -- acknowledges that the assumed flat customer profile is likely to be imperfect, doesn't it?

A. (Mowatt) I would agree to that, yes.

Q. And PHP's actual load can change as a result of production conditions, maintenance, outages and other factors unrelated to Nova Scotia Power's dispatch.

A. (Mowatt) Correct. I will caveat that, though, in terms of the calculation at the end of the year. One of the benefits of that is that we see the total load that PHP would have consumed and the number of outages that it would have had due to whatever reason, so although you're correct that the timing of the outages, Nova Scotia Power wouldn't be able to necessarily forecast, we do know the number of outages that it would have taken on an actual year because we're using that actual load profile and the number of down days.

Q. Okay. But the dispatch credit is aimed at addressing reductions that result from Nova Scotia Power's economic dispatch, so if the load reduction is caused by Nova Scotia Power providing the direction, that's the type of savings that the credit is meant to recognize.

A. (Mowatt) Yes.

Q. And to distinguish between dispatch-driven load reductions and load reductions caused

by some other non-dispatch-related factor, describe to me how the proposed tariff does that.

A. (Mowatt) So the dispatchable rider will include all deviations of load for whatever reason, so to your -- to your premise that Nova Scotia Power provides the schedule and PHP can choose to not follow that or for whatever reason did not follow that, that would be the optimal schedule at that time. Comparing that to the levelized schedule that Nova Scotia Power would calculate at the end of the year is appropriate because it captures all of the deviations compared to that levelized load. PHP choosing to run through it or economically -- or sorry, for equipment reasons not being able to ramp up and load, say. By comparing it to that levelized load, you are capturing all of the load-shifting benefits as compared to them running at a levelized load, not being responsive to price signals or a schedule.

Q. But there is a limit to the

accuracy of that levelized load, isn't there, or whether or not it truly represents how PHP would run, absent dispatch?

A. (Mowatt) I think it's our best estimate that we'd be able to -- to establish in how PHP would run, absent any form of economic optimization on the system.

Q. And the setting of that CBL, has that been a -- that has been a characteristic of the existing ADC Tariff?

A. (Mowatt) There is some difference in the setting -- the load itself, setting that, yes. But it's not similar to the ELIADC in terms of costing out a dollar per megawatt hour function of that.

Q. So the setting of the level, the quantity of it, is being -- that's being done in a similar way that it has been done currently? You're proposing to continue that same methodology?

A. (Mowatt) Of just the megawatts.

The DR calculation itself, I would say, is an improvement on the benefit as it focuses solely on load-shifting and some of the other characteristics that we would have talked about yesterday, changes in forecast versus actual and changes in pricing, are removed from the specific DR calculation.

Q. And for the dispatchable rider, under the current ADC Tariff, there's benefit sharing and so -- and the benefit sharing limited the amount of overstatement of -- that's passed through to customers.

Credit is being shared under the current mechanism.

A. (Mowatt) Correct.

Q. And you're not proposing that sharing mechanism going forward?

A. (Mowatt) Correct.

Q. Okay. And why is it that the company's proposing to eliminate that sharing mechanism?

A. (Mowatt) As we stated yesterday,

the ELID Tariff is designed such that other FAM customers should be indifferent to the dispatchable rider, given the fact that they're going to be set at that levelized load. So currently, if we think about ELIADC, the exposure to FAM customers is on PHP's total load, how that would shift in a given year.

Now the calculation is shifting it more so such that FAM customers are exposed to simply the -- or I shouldn't say simply, but the DR benefit itself, which is just how well PHP can shift load -- shift its load on an actual basis versus the levelized.

So we're comparing apples to apples in terms of your actual load that's being used for the calculation of the CBL. The costing methodology is the same in terms of the pricing used in both methodologies, so now it's simply looking at that delta or that deviation between those two.

The financial incentive for PHP to capture that DR benefit is one that benefits the system as

we've discussed today and yesterday, and it's -- better aligns incentive to follow the optimized dispatch with the DR credit.

A. (Ferguson) If I could add to that, Mr. Mahody.

And a key element for us is that the levelized load, PHP's load, is costed out on the beta cost basis and according to other above-the-line customers. So there is a contribution to the system through that methodology that's different from the ELIADC.

Q. The consequence of the currently existing sharing mechanism, do you agree that one of the reasons, for instance, why there's no customer charge under the ELIADC is because of the sharing mechanism in existence?

A. (Mowatt) I do.

Q. And because there's no customer charge in place right now is one of the reasons why, I take it, NSP has not been tracking the costs associated

with administering that tariff.

A. (Mowatt) Yes.

Q. And yesterday, there was some testimony regarding efforts that could be made to track costs and going forward under the ELID what would be done.

You do agree with me that it would not be a simple task to identify all of those costs associated with administering the ELID Tariff going forward?

A. (Mowatt) No, I would agree. Just to give a little bit of context on that, it's not like it's a single FTE or anything to that nature, but it crosses multiple roles in that function, so it is, as you said, complicated.

Q. But isn't one method to address that complexity and eliminate it perhaps to have a sharing mechanism in the ELID Tariff similar to the ones currently in existence?

A. (Ferguson) I don't think it's best addressed through that mechanism. I think the

company's view is Port Hawkesbury Paper will be on an above-the-line rate, costed on that basis, and, in accordance with that, the decisions to follow and adhere to the company's dispatch are Port Hawkesbury Paper's to make based on the circumstances that they face.

So it's their -- having been costed and priced on an above-the-line basis, the DR is really a tool for them to make the most advantage of the flexibility of their load and, in the company's opinion, in accordance with that, it's appropriate those costs flow fully to Port Hawkesbury Paper.

I think the -- recognizing the complexity of the costing of the customer mechanism, I think, is best addressed through a good analysis on that front. It does have complexities, there's no question. We'll have to make some estimates and probably some allocations, but I think the best approach is to focus on providing a high-quality forecast like other elements of our GR-related activities through a GRA.

THE CHAIR: Mr. Ferguson, in terms of the embedded cost nature based on the levelized load, the theory is that PHP would be highly motivated, absent the dispatchable rider, to operate on that basis?

MR. FERGUSON: Yes.

THE CHAIR: And would you agree with me that it's unlikely that PHP could actually operate on the most optimized basis?

MR. FERGUSON: It probably is an assumption that favours Port Hawkesbury Paper actually achieving that across the year. We'll have challenges.

However, I think those challenges -- benefits to other customers from that operating assumption exceed that because, again, with a load of the magnitude of Port Hawkesbury Paper, if they were relying solely on demand and an energy charge and indifferent to when they ran with their costs being shared among all of their FAM customers like other above-the-line rates, absent this driver, I think there's, in my opinion, more risk for

other customers. So the baseline, starting point may be favourable, but I think there's, in my opinion, more in for other customers with respect to a strong incentive from the system's largest customers to -- customer to operate optimally.

THE CHAIR: Okay. But just in terms of it may be favourable, there's no "may" about it. It is favourable to PHP, isn't it?

In any scenario in the real world, they're likely to operate at some degree of suboptimal -- on a suboptimal basis compared to the optimal levelized load that NS Power will calculate.

MR. FERGUSON: Yeah.

THE CHAIR: And so in terms of the embedded cost nature, the embedded costs that would flow as a result of that would be more based on that real world suboptimal level than it would be based on the levelized level that Nova Scotia Power's calculating.

MR. FERGUSON: Yes, I expect so.

Their best-case scenario is probably less optimal than a levelized load across the year.

THE CHAIR: But the degree can't really be determined.

MR. FERGUSON: Can't be determined and you get into a lot of other issues around what large industrial customers might think of when they determine their optimal profile. It's again -- yesterday, we talked about it ratcheted demand, then once you hit that in December, January, February, then you carry it all the rest of the year. How does that affect how you think about how you run in June? You might be indifferent if you'd established a large demand.

Anyway, there are a number of factors.

THE CHAIR: Thank you, Mr. Ferguson.

Sorry, Mr. Mahody.

MR. MAHODY: Not at all.

BY MR. MAHODY:

Q. The panel's aware that Bates

White has proposed a true-up to address substantial deviations of PHP's net load from expectations.

A. (Willett) Yes.

Q. And Mr. Willett, is there anything from Nova Scotia Power's perspective that would be a barrier that would make the -- making -- giving effect to Bate White's recommendation unachievable, from the company's perspective?

A. (Willett) Maybe it would be just helpful to pull up the specifics of the recommendation there. I just want to make sure on the same page.

Q. Okay. N-20.

THE CHAIR: I'll just flag, Mr. Mahody, if you see a convenient spot to stop in the next few minutes or so, it's probably time for our morning break.

MR. MAHODY: This might be an appropriate time, Mr. Chair. We'll just pull up that reference, and we're set to go as soon as we come back.

THE CHAIR: All right.

So it's 25 to right now, so we'll come back at 10 to 11:00.

--- Upon recessing at 10:35 a.m.

--- Upon resuming

THE CHAIR: Okay, Mr. Mahody. I think we're good to go whenever you're ready.

MR. MAHODY: Thank you, Mr. Chair.

MICHAEL WILLETT, Resumed:

ERIC FERGUSON, Resumed:

CRAIG MOWATT, Resumed:

DAVID STANFORD, Resumed:

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

Q. So for a record reference, N-20 is the Bates White report and at page 35, if we could call that up.

Mr. Willett, there are a couple of references. This is the first one I wanted to just make reference to.

So it's down at the bottom -- near the bottom of this page. "In addition to correcting" -- beginning at line 23:

> In addition to correcting the Energy Charge rates, we recommend that a true-up mechanism be created to address substantial deviations of PHP net load from expectations...

And there's one reference -- another reference I'd just draw to your attention is in response to IG IRs to Bates White

MR. MAHODY: So that's Exhibit N-31, Mr. Norwood, IG IR-11.

And if we can scroll down a little bit further?

BY MR. MAHODY:

Q. And here, in responses to 11(a) and (b), there's additional references to the true-up that's being proposed.

So from a description perspective, Mr. Willett, that is what I had in mind about what's being described. And my question was whether or not there are

any impediments to Nova Scotia Power implementing such a true-up mechanism.

A. (Willett) So I would say our rates have been established based on assumptions at a point in time, so that's how all the above-the-line classes were determined during the GRA process. We would have had a load forecast and also the assumptions for the wind, and that's how rates would have been established.

We do have the FAM mechanism, which would true-up a large component of the energy charge, but it's not typical to be changing the assumptions related to -- you know, assumptions -- load expectations are going to change over time. You need to draw a line in the sand when you're establishing those rates. And I would say that the FAM mechanism is what would true-up the majority of those rates, but there's no mechanism on the non-FAM component of the energy rate.

Q. "Typical" seems to be a difficult descriptor to use in this hearing, Mr. Willett, to be

direct.

But let me just come back to the question, though. Implementing the type of true-up that Bates White has described here, am I hearing, then, that you would have a preference about what use could be made of the FAM, but are there any impediments to implementing the type of true-up that Nova Scotia Power's indicated here, subject to your comments about it being atypical?

A. (Willett) I would just say that there is an opportunity to calculate it, but we just haven't felt that that is an appropriate item to do on changing the energy charge, based on actual results and being atypical to the treatment of all other customer classes.

Q. Understood.

But if directed to do so, you'd be in a position to be able to comply with that direction.

A. (Willett) I would expect we would be able to calculate it. I haven't gone through all the

details, but I can't think of anything right now that would impede that.

Q. Okay. Thank you, Mr. Willett.

Mr. Mowatt, my final question just returns to the implementation of discretion by Nova Scotia Power when calculating the savings created by Nova Scotia Power's dispatch. And I want to take you to a particular reference and just get your comment on it.

MR. MAHODY: In the proposed tariff itself -- I'm at Exhibit N-1 at PDF page 27, please, Mr. Norwood.

And if we can just scroll down, it's the paragraph that starts with, "Savings created".

BY MR. MAHODY:

Q. So Mr. Mowatt, here the proposed tariff indicates:

> The savings created by NS Power dispatch of the Customer load (DR credit) will be calculated at yearend by comparing the actual system costs with the Customer's actual dispatched load to a scenario where the actual Customer load is replaced by the

> high load factor customer profile (i.e. the ... (CBL)) which incorporates actual Customer load, the dates and durations of the Customer's major scheduled maintenance periods and other factors as may be appropriate to calculate a representative CBL.

Do you agree with me that, for that last portion, "which incorporates," and then from then on in that section, that there is discretion that is applicable to making those determinations?

A. (Mowatt) Thank you for the question, Mr. Mahody.

The calculation of the CBL itself, as I've -- I believe I described yesterday, where we're taking the ending year load and reducing that number by the number of down days and then dividing that by the number of hours in which PHP is up is a fairly straightforward mathematical process.

I believe the question that you have around discretion, I wouldn't -- I wouldn't phrase it as "discretion". The randomization of the outages can be

completed using a random seed generator in Excel, so that can be spread out so -- such that every month has a similar number of outage days, and within each month those outages are randomized. That wouldn't be towards Nova Scotia Power's discretion. That's just the mathematical way that that would be completed.

Q. Fair enough.

But with a tariff that allows you to consider other factors as may be appropriate, is that -- is that not -- that's discretionary?

A. (Mowatt) So I think, Mr. Mahody, where my -- where I would go with the other factors is, I can't think of any other factors off of the top of my head that would deviate from that mathematical process. Not to say that there might not be something that happens in the future, but from where I stand today, I would see it more as a -- the mathematical process that I laid out where it is formulaic to come up with the outage profile like I discussed, the randomization. That would go into some

form of replicable mathematical formula and then spread over the year appropriately.

Q. Okay. But you agree with me that if, after today, you did land on an item that was to be considered, there's discretion under the tariff to consider that item.

A. (Mowatt) I would agree with that, yes.

MR. MAHODY: Just one final clarification, if I could, Mr. Chair.

Earlier, there'd been an undertaking near the beginning of my questioning about the RECs and an undertaking to indicate any differences that may exist in the previous RECs that were referred yesterday.

BY MR. MAHODY:

Q. I just had two items that I'd like referred to included in that undertaking response, if you're prepared to accept it, Mr. Mowatt.

And that is confirmation that the

Goose Harbour RECs are compliant with the renewable energy standard and, secondly, that the RECs purchased by Nova Scotia Power from Newfoundland were also compliant.

Were you prepared to those -- include those in addressing your undertaking?

A. (Mowatt) I can, yes.

MR. MOWATT: If I could ask, Mr. Chair, the undertaking would include those two items.

THE CHAIR: Okay. And then that would be Undertaking U-11 would be revised.

MR. MAHODY: Those are my questions. Thank you.

And thank you, witnesses.

THE CHAIR: Mr. Melanson.

MEMBER MELANSON: Thank you, Mr. Chair.

QUESTIONS FROM MEMBER MELANSON

Q. I'll start off just to make sure that we're all on the same page as to where we are.

So if the Board either refuses to approve this tariff, or makes modifications to the tariff that are not acceptable to PHP, then the only two options that exist currently would be to take service under the LIIR or have an extension of the ELIADC. Is that a fair assumption?

To be in place by January 1st, 2027.

A. (Ferguson) I pause, Mr. Melanson, on the LIIR.

Q. Right. But are you saying -- let's get on that one.

A. (Ferguson) Yeah.

Q. Do they qualify for that tariff?

A. (Ferguson) Well, the provisions are, I think it's 2,000 kVA and above, so they do. I think it would -- there's a question to be addressed

around whether the service to Port Hawkesbury Paper is comparable to the service in the class. I think that's an outstanding question for me.

Q. So that if -- because, I mean, the options -- that tariff exists, so if a customer comes that's above the 200 kV -- above the threshold and says, "We want service under this tariff," why would you not have to provide service under the tariff?

A. (Ferguson) I think you have to understand what the implications are for all of the customers who are currently part of that class. If you're part of the class, then, for instance, for FAM, the costs -- your portion of FAM costs flow to the class and are affected or you -- your billing determinants, potentially, would affect the rest of the class. And it's just a -- for a customer of this magnitude and these load characteristics, I think there's an initial screening that would have to happen.

Q. But if the wording -- if the

wording says that they fit under the class -- I understand the impacts that might have, but the wording says they fit under the class, can you deny service?

A. (Ferguson) Well, it's not a situation I'm aware we've faced before. But really, I just -- I can't give an outright yes because I think there's other matters to be considered, and I expect, you know, it's just -- I can't give you an affirmative for that without really understanding what the implications are for other customers on that -- in part of that class.

Q. Sure. Okay.

And assuming that the company could come under that class, the dispatchable energy portion of the current ELIADC would be lost; correct?

A. (Ferguson) Yes.

Q. Okay. With respect to the situation we're in and the various proposals that have been made surrounding certain adjustments, from a purely financial cost recovery point of view for Nova Scotia

Power, if we make all or any of the adjustments -- some are -- you know, you can't do one -- two at the same time, but if you make some of these adjustments that are requested, because of the deferral account, would Nova Scotia Power be kept whole with the suggested deferrals or changes that have been made -- or suggested? Sorry.

A. (Willett) So I would say that's -- that's true for 2027 and, beyond that, obviously, the deferral was approved for '26 and '27.

Q. Okay. But I'm assuming that Nova Scotia Power would not be indifferent to the amount of the deferral. Am I right about that? If one were to be required.

A. (Willett) So the deferral would be recovered from other customers and, obviously, the company -- you know, rate pressure for other customers is always a concern for the company, but from a revenue collection perspective, the company would be expected to be kept whole with the deferral mechanism.

Q. But is there a limit to how many deferrals you can have?

I mean, there are a lot of deferrals and a lot of situations that come up that might require deferrals. Is the amount of any deferral a concern to Nova Scotia Power from a flexibility -- financial flexibility point of view?

A. (Willett) Yes.

Q. Which brings me to this notion that's been discussed with respect to the Settlement Agreement and the fact that, as it's worded, the parties have taken the position that they can take any position they want. And assuming the Board accepts that proposition, does that mean that -- people can present any position they want in almost any application. Does that mean that the Board should just completely disregard the Settlement Agreement and give it no weight if it starts considering these various -- these various proposals, or does the Settlement Agreement still carry some weight in

that deliberation?

A. (Ferguson) I think that's dependent on the magnitude of the changes that the Board might impose.

Q. Turning to some specific items, and I'm not going to be that long, but the -- one of the concerns expressed related to the fact that the peak load, through the ELIADC for years, is influenced by Nova Scotia Power and that creates somewhat of a difficulty in establishing what the PPC load should be. And I assume you agree with that.

A. (Ferguson) The peak for costing?

Q. Yeah.

A. (Ferguson) The company's put a proposal forward, but it's, of course, subject to whatever the Board approves in this case.

Q. But the issue of Nova Scotia Power influence because it's been able to influence dispatch, being able to influence over the last number of

years that peak factor, that peak number, that creates a -- somewhat of a conceptual problem, doesn't it, when you're trying to analyze what that number should be?

A. (Ferguson) Yes.

Q. And my question is, since the dispatchable character of the -- of the load is kept in the ELID, isn't that going to be a continuous issue going forward?

A. (Ferguson) I think it gets back to the -- you know, the fundamental objective of the dispatchable rider in particular, is that we are trying to create a framework under which Port Hawkesbury Paper can take advantage of the load flexibility to minimize its costs. At times, that'll mean they will run at very low load during a period of system peak. And we use the three highest peaks in each of December, January, February to do that. And that costing methodology, looking at historical and forecasting and forecast peaks works well for other classes. In our opinion, it doesn't work so well for a

class with one customer on it, where the variability can be so great and the load at time of system peak, for solid reasons, economic dispatch, may be very low. So if it is dropped very low, as low as their firm load, for instance, would that be an appropriate determinant upon which to base -- to determine its responsibility for transmission to generation-related costs? Our view is it wouldn't. It needs to be something that more effectively balances its load at time of system peak and its reliance on the transmission and distribution systems. So that's where the judgment will be required going forward.

Q. Okay. The suggestion from the Industrial Group's expert about the 120 megawatts, that method of calculation is not really influenced by Nova Scotia Power's -- by the dispatchable nature of the power, is it? Because it's based on an annual number, not on ---

A. (Ferguson) Correct.

Q. But from your perspective, why is that an appropriate number to use?

A. (Ferguson) Well, that's -- it's an average number, as I understand it, across the year. Likely to be higher than their load at time of system peak. So I guess, first and foremost, we've relied on the 65 because we believe it was established through the Settlement Agreement. But we also think it has the foundation of appropriately balancing general use across the year with use at time of system peak.

Q. The -- there was some discussion yesterday about the 10 percent, I would call it, premium on the interruptible component. And if I understood the answers correctly, there was indication that if the Board were to move to the 13.107 number for the interruptible credit, that you did not support the corresponding change to the premium. Am I correct about that?

A. (Ferguson) Yes.

Q. Okay. So that in essence, you're looking at sort of a capped number for the premium, would that be fair?

A. (Ferguson) Yes. Really the circumstance was we modelled the 10 percent, and that's approximately the half million dollars and then we began to think about the test question about what is the true value of this and who should benefit from -- who most benefits from priority interruptible service? And the more we thought about it, the more complex the question became. So we reached a position where -- and we were mindful that we have acknowledged that there's also reliability benefits associated with ADC service. So it's a bit of a figure that's just -- we've recommended be adopted to recognize all those potential values and the view that it would be premature to discontinue it until we complete that full analysis.

Q. Okay. And on that same point with the interruptible credit of 13.107, if I understood that, that's the one that's applicable to the other LIIR -- or to the LIIR customers; correct?

A. (Ferguson) It's the same basis,

the avoided cost of a combustion turbine, but the price is different because it's one customer and their interruptible load is such a large portion of the total load. There's some dilution among the other large industrial class because the portion of forecast load on peak, the forecast demand -- interruptible is significantly less than the total load on peak. And plus it's priced according to the non-coincident demands that occur throughout the year. So that's how you end up at 787. The cost structure is the same, the avoided cost of a combustion turbine, but the math after that point produces -- would produce a $13 figure for Port Hawkesbury Paper versus the $7.80 for the Large Industrial Interruptible Rider class.

Q. So if you have the same basis but the math here is a different result, why is that result not the correct result?

A. (Ferguson) The company's view is that it was an element addressed in the Settlement

Agreement and it was agreed by the parties that they would use the value from the Large Industrial Interruptible Rider class, interruptible credit.

Q. I'm going to turn to a completely different topic I don't think has actually been addressed in this hearing; it was to do with the *More Access to Energy Act*. And the four factors that the *More Access to Energy Act* requires us to consider when we're looking at -- well, it requires to consider many circumstances, but including when looking at the tariff. And one of them is to, "support competition and innovation in the provision of energy resources in the Province". Has the company considered that consideration when developing this tariff and when it's been looking at the other proposals that have been put forward in this hearing, the idea of supporting competition and innovation in the province? Does it even apply to this type of tariff?

A. (Ferguson) We didn't go through that exercise of evaluating it. I don't think there's any

question that it is an innovative rate structure. We're trying to integrate the largest -- the load of the largest customer on the system within the dispatch. Real-time dispatch of the utility is something unusual in the industry.

Q. The other -- I mean, there's four factors that we're required to consider. So I'm just going to bring them up because I might raise some other issues with respect to people that want to make their submissions, but I think there should be an opportunity to address those four factors if you want to or can. But the other factors are, "support the development of a competitive electricity market". Is this tariff implicated in that? We have a wind farm that impacts the tariff, but does the tariff itself have any impact on the development of a competitive electricity market?

A. (Ferguson) The tariff accommodates the existence of the Power Purchase Agreement and the Sales Agreement, which is enabling non-utility-

owned generation. So I guess it does from that perspective at the wholesale -- as I think of it, at the wholesale level.

At the retail level, it still is a bundle service provided by Nova Scotia Power, subject to the agreements, so...

Q. And I take it if you've not really analyzed the issue, you haven't analyzed whether one proposal supported better than another proposal? Would that be fair? From the evidence that's been presented here.

A. (Ferguson) That's true. Really, the genesis of this was the GRA Settlement Agreement and our previous work with Port Hawkesbury Paper. So it continued on that path. It didn't really pause to do the evaluation you're talking about.

Q. The third factor is to:

> ...ensure the provision of safe, secure, [and] reliable and [economic] energy supply in the Province.

So, I mean, that's a fairly general category, but was that considered at all?

A. (Ferguson) I don't want to suggest that we did a separate evaluation. We didn't, from that context, that I'm aware of. But we certainly have a long history of working in a safe and adequate manner with Port Hawkesbury Paper in the dispatch of their load. And it's certainly trying to get it to an economic -- overall economic solution

Q. And I take it you haven't analyzed what the best economic solution is, based on all the various proposals that have been put to us?

A. (Ferguson) For me, it's clear that the best economic solution is one that provides the appropriate cost-driven information to the customer. So this is based on the economics on an hour-to-hour basis of the power system and provides that information, processes that information, and provides direction to Port Hawkesbury Paper with respect to dispatch to produce the

overall lowest cost of the system. So to my mind, a pretty powerful economic tool.

Q. And the last criteria, "support sustainable development and sustainable prosperity". Again, do you have any comments about that with respect to this tariff and how we should approach that deliberation?

A. (Ferguson) What comes to mind is the earlier discussion around the construct accommodates the Power Purchase Agreements and the supply of electricity to Port Hawkesbury Paper from its wind facility -- it's sister wind facility at Goose Harbour Lake.

Q. Okay. Thank you. Those are all my questions.

MEMBER MELANSON: Thank you, Mr. Chair.

QUESTIONS FROM THE CHAIR

Q. I'm going to apologize in advance a little bit. The ground has been well covered. These are going to be a little bit scattered and probably more at the edges than some of the other questions that have already been covered. I'll try to get through them as quickly as possible.

THE CHAIR: First, if we could pull up, Mr. Norwood, Exhibit N-1(i), please? It's an Excel spreadsheet. And if we could go to the ELID rate design tab on that, please?

BY THE CHAIR:

Q. Does this show me the annual energy and demand charges or revenue from those charges under the proposed ELID Tariff?

A. (Willett) Just give me a second. I'm just opening it myself so I can take a look.

Q. Yeah, it's a little ---

A. (Willett) And can you just repeat

the items you were looking for?

Q. I was curious whether from this I can see the revenue that Nova Scotia Power anticipates will be generated from the proposed tariff. And just to be a little bit more focused, if we go to cell L-21 for example, does that show me what the intended -- or the anticipated revenue from energy charges would be from the tariff in 2026?

A. (Willett) And I just want to -- I can't see which tab you're on. The 2027 smooth tab? Is that...?

Q. No, it's ELID rate design tab.

A. (Willett) Okay. Perfect. Thank you. And the reference was L-27?

Q. L-21.

A. (Willett) Oh, 21. Thank you.

Yes, that's correct.

Q. Okay. And so I think, then, in L-44 we see, for 2027, energy charges of 34.2 million

compared to the 80.9 million for 2026?

A. (Willett) Correct.

Q. And the difference, I take it, is because of the -- Goose Harbour coming online is reducing the energy consumption?

A. (Willett) That's correct. In -- yes, there's approximately 300 GWh.

Q. Okay. And in terms of 2027, we'll stick with 2027, if we go over to S-44, we see a revenue of 5.7 million. I'm correct that that's the revenue that's expected to be derived from the demand charges proposed under the tariff?

A. (Willett) That's correct.

Q. And then in W, Column W there, the 39.9, that would be the total demanded energy charges for the -- under the proposed tariff?

A. (Willett) Correct.

Q. And those numbers, as I understand it, don't account for the $120,000 for customer

charges?

A. (Willett) I'm just trying to see if we had that in here, but I don't believe those are in there.

Q. Okay. And it also doesn't account for any credits under the dispatchable rider?

A. (Willett) Correct.

Q. And if I understood Nova Scotia Power's evidence correctly, at least the initial estimate of the impact of the dispatchable rider credit based on an analysis from 2025 was theoretically in the range of 7 to 11 million, but more likely to be about half that amount?

A. (Willett) That's correct.

Q. Okay. So once Goose Harbour comes online, then the reduction of charges under the tariff compared to the -- what the embedded cost framework for it are probably somewhere in the range of 10 percent to 25 percent?

A. (Willett) Correct.

Q. Okay. And I'm going to go to another exhibit here. And -- but I want you to remember two numbers from this particular exhibit. You're going to write them down. So the total revenue derived from energy charges in 2027, which was 34.2 million, and the total revenue derived from demand charges in 2027, which was 5.7 million.

THE CHAIR: Now, Mr. Norwood, if we could go to Exhibit N-6? And page 12 in the PDF.

BY THE CHAIR:

Q. So in this particular IR, Nova Scotia Power was asked to provide cost-of-service information models for various scenarios that were presented by the Industrial Group arising from the evidence that Nova Scotia Power and Port Hawkesbury Power -- Port Hawkesbury Paper had filed?

A. (Willett) Correct.

Q. And am I correct that what's requested in the question part (a)(i) of the question:

> Using a PHP firm load of 8 [megawatts] for 3 CP and 57 [megawatts] of interruptible load, as proposed by NSPI, priced at the NSPI proposed credit rate...

That's essentially the tariff as proposed, that particular model?

A. (Willett) That's correct.

Q. Okay.

THE CHAIR: And if we could just go ahead to page 14 for a second, Mr. Norwood, in the PDF?

BY THE CHAIR:

Q. In the response, Nova Scotia Power has referred to Partially Confidential Attachments 2 and 3 for that particular scenario?

A. (Willett) Correct.

Q. And two is 2026 and three is 2027?

A. (Willett) That's my understanding. And I believe there's an earlier attachment which provides a summary of all the results.

THE CHAIR: I'd like to go to

Attachment 3, which is the 2027 model. Mr. Norwood, if we could go to -- I'm going to look at Exhibit 10 in the document; that's page 220 in the PDF.

Oh, I gave you the wrong page then, I guess. Exhibit N-6. There we go.

BY THE CHAIR:

Q. In this particular exhibit in the document, row 8 references the extra large industrial two-part real-time pricing tariff. I don't know if that's an error, or that's supposed to be Port Hawkesbury Paper?

A. (Willett) Yeah, so just to explain, any time where it does say ELI two-part RTP, that class was there. So for convenience purposes, to move PHP, we've just replaced, but there's some instances where that just didn't get replaced in error.

Q. Okay. And so if we look at Column 6 under that particular row, we see the 39.9 million in revenue expected from the tariff in 2027?

A. (Willett) Yes.

Q. And in Column 5, as I understand it, that's the actual allocated cost, as opposed to the revenue that is expected to be derived from the rate as designed, producing that 104.71 revenue to cost ratio in Column 7?

A. (Willett) Apologies; that column would represent what the cost of service before the application of the R/C ratio, correct.

Q. Now, Column 1 show demand-related costs allocated to the class and Column 2 show energy-related costs allocated to the class?

A. (Willett) Correct, yes.

Q. And just referring back to those numbers I asked you to mark previously, so focusing on demand for a second, under the cost-of-service model, demand-related costs assigned to PHP based on the rate as proposed, about $12 million, but the demand charge itself, it looks like it's only designed to recover 5.6 -- sorry; 5.7 million. I'm just wondering what the reason was for

that or how that happens.

A. (Willett) That's a result of a portion of demand costs are recovered through the energy charge. So for instance, within fuel itself there's a component of fuel costs that are considered energy and demand, and so the cost of service would be recognizing the classification of those costs within the cost of service, but the rates themselves, there is a component of the energy charge that is recovering demand-related costs.

Q. So the numbers I'm seeing here on Exhibit 10 that are showing, that's the -- those are the fully allocated costs based on energy and demand with respect to the class?

A. (Willett) That's a result of, yes, the cost of service and where those classes -- costs have been classified within the cost of service, correct.

Q. And sorry, I should have asked this earlier, the scenarios that you presented, do these also account for changes in fuel cost between the various

scenarios? Or is that -- are those fuel costs allocated outside of this model?

A. (Willett) Yeah, so there is a separate model that does fuel, but what happens is that the results from that would be brought into the cost of service.

Q. Okay. So that's all included. Okay. So then I wasn't quite sure I followed the previous answer in terms of there's something in the design of the rate that transfers some of the costs that are allocated to demand into the energy charge?

A. (Willett) Yeah. So to what I explained before, I believe there is a component of the demand in energy, but I would need to take it away to get the specifics of that in order to break that down.

Q. Okay. Well, if you wouldn't mind taking an undertaking that would kind of reconcile, I guess, how you get from the fully allocated demand and energy cost to the revenues that -- the demand and energy

revenues from the rate, that would be appreciated.

THE CHAIR: That would be Undertaking U-13.

UNDERTAKING U-13 - To reconcile how you get from the fully allocated demand and energy cost to the demand and energy revenues from the rate

BY THE CHAIR:

Q. In Nova Scotia Power's reply evidence, it seems to acknowledge that there's kind of a regulatory foundation for the various alternatives for the demand charge that were presented in the evidence; in particular, the Port Hawkesbury Paper 8 megawatt and Mr. Bowman's 120 megawatt?

A. (Willett) We did, yes.

Q. And regarding Port Hawkesbury Paper's position that 8 megawatts be used, I think Nova Scotia Power suggested it could be justified based on cost

causation, as determined by firm load at the time of system peak?

A. (Ferguson) I would say we understand the concept of cost causation and that generating capacity in particular is driven by firm load, but we don't think it can be supported by that.

Q. Okay. So you think there's a regulatory foundation for it and you also don't think it can be supported? I'm not sure ---

A. (Ferguson) Sorry; I just meant in regulatory practice, cost causation is a recognized consideration. But I think it has its limits is what we're really saying, so...

Q. Okay. All right. And in terms of that, that particular approach, the same approach is also taken with the Large Industrial Interruptible customers where their 3CP load is determined both on firm and interruptible load at the time of the system peaks?

A. (Ferguson) Yes.

Q. And is there a cost justification or a rate-making justification for treating the approach differently for those two classes?

A. (Ferguson) There is, to my mind, for Large Industrial Interruptible rider. It's a practice that's been in place for decades, and I understand it's common across the industry. And I think it works well when you have a class with several customers in it and different load profiles that will behave differently across the year, and the 3CP metric produces a reasonable overall outcome.

Where we diverge with this tariff is it's one customer and with a highly variable load that just requires us to -- it's probably stretch -- in my opinion, stretches us beyond what the established practice -- applying the established practice to that variable load doesn't produce a fair outcome, in our view.

Or excuse me; we really are proposing the established practice because we are relying on the 65

megawatts and what's established over time. But just going forward, as that load at time of system peak varies, we're of the view that it's -- it will need to look beyond what the actual 3CP number is to make sure that it produces a fair outcome.

Q. And I guess this goes back to some of the questions Board Member Melanson asked, and others. I mean, is going forward as this is revisited in General Rate Applications if the rate is approved, is this going to be a constant debate over a really subjective demand allocation in -- under this particular rate design?

A. (Ferguson) It's certainly unique to this tariff that we have to go through this process. But I expect -- number one, we believe that where we're starting is a reasonable outcome and reasonable for the test year period. But once that's visited with the benefit of this proceeding and experience with the tariff, my hunch is that what's established the next time around will be a much more longer-term process that will be more

definitive going forward and likely won't have to be -- won't be a large undertaking to revisit in every GRA; rather, we'll rely on the information that we use through this through proceeding and analysis in the next proceeding, and my expectation is what comes out of that will be reliable for the long-term.

Q. Why do you expect that there will be sort of better information to define or divine an appropriate demand number in the next GRA?

A. (Ferguson) Because my view is that that question will be front and centre. How do you establish the demand determinant for a load of this variability and a load of this magnitude that relies on the power system to the extent it does? Is it actual results in conformance with the other tariffs, or is there some other consideration process that needs to be considered? Is it an average load, as Mr. Bowman would recommend, or is it somewhere between loaded time of system peak, subject to the company's dispatch, and

average load, which is where we are in this proceeding?

Q. So in terms of analyzing the number, it's always going to be subject to Nova Scotia Power control, to a certain extent, because it's going to be dispatched. How helpful, going forward, is the actual data going to be in coming up with that number?

A. (Ferguson) My view is the actual number will be less important than the notion around just what's the appropriate determinant that provides for fair allocation? The objective of the tariff is to produce near-term economic benefits. So I think it's more a case of what's the appropriate demand determinant for a customer who varies between 8 megawatts and 150, 160 across the year?

Q. So would it be similar to some of the other items you might argue about in a cost-of-service proceeding where there's theoretical approaches to allocating costs that, you know, may have some degree of validity to each of them, but ultimately you have to pick

one and that's what you go with?

A. (Ferguson) I expect so.

Q. In their reply evidence, and I can pull it up and refer you to specific comments if you like, but just for sort of a general proposition that BAI seems to be of the view, or expressed in their evidence, that the reduction of demand on peak by Port Hawkesbury Paper would serve to reduce the need for expensive increases in both generation and the transmission system. So in terms of avoiding capacity costs, that they could equally avoid capacity for both transmission and generation infrastructure because of a reduction in demand on peak.

I take it Nova Scotia Power does not fully agree with that view?

A. (Ferguson) No. Our view is that it can produce savings, in terms of generation, avoided generation builds, but not really affect transmission.

And then I might ask Mr. Stanford if

he wishes to add to that.

A. (Stanford) Yes. No, I concur with what Mr. Ferguson said, is that it -- you know, in general, transmission is built to accommodate firm and interruptible load, so...

Q. And Mr. Mahody asked this, but I confess I wasn't quite clear on the answer, but what is the reason then that the same cost of service allocator is used to allocate both generation and transmission capacity costs?

A. (Stanford) So I would say it's really around the historical foundation of that that's been the methodology that's been employed, the generation and transmission have both had the same demand allocator of the 3CP. I wouldn't go much deeper than that, but it's based on that historical use of those both being consistent across both of those functions.

A. (Ferguson) And if I could just add, the methodology is to first allocate demand-related

costs based on 3CP. But then step two in the process is to recognize the value of interruptible load in the form of an interruptible credit. And that interruptible value is purely a capacity -- generating capacity value, which in my mind recognizes that that's the saving -- system savings that's being created by a customer agreeing to accept interruptible service.

Q. Okay.

THE CHAIR: Mr. Norwood, I think we're going to stay in the same exhibit here, but if you could go to page 7, please?

BY THE CHAIR:

Q. So this is Information Request 5. I'm just going to -- so the question was premised on a comment that Nova Scotia Power had made in its Application on page 6 and the statement was:

> Consistent with the foregoing, it is proposed that the assumed costing/billing demand also be adopted and applied for billing purposes throughout the year (i.e. the PHP 3CP figure employed for [the] Tariff costing and pricing would also be applied

for billing purposes essentially making the demand cost recovery a fixed charge).

And there's a response that's provided in the information -- in the IR response. I wasn't sure that I fully followed it, and I was hoping you might be able to walk me through what is the costing and pricing methodology that's applied to other above-the-line customers and why this is -- how this is different and why?

A. (Ferguson) For demand of other above-the-line customers, you rely on a forecast to calculate the demand-related costs, make -- determine what the appropriate billing demand are for those customers, and the price is what comes out the other end. So depending on demand, actual billing demand, the revenues will change.

In this circumstance, recognizing that -- so there's a variability and a forecast error, which results from what I just described, but those are normal forecast errors and muted by the fact that the class is

made up of several customers, many customers who will vary over time, but on balance, you get a reasonable level of predictability.

For this customer, you won't have that reasonable level of predictability. So the notion is you can avoid that forecast error which is going to result -- likely to result for this customer just by using the same determinant for billing purposes, for costing purposes as for billing purposes. And again, I think it works because it's a single customer in a class.

Q. Okay. So if I follow that, then, am I correct that for the large industrial customers, then, or for any customer, above-the-line customer that has a demand charge, demand costs are allocated in the same way as they are for PHP based on 3CP allocator?

A. (Willett) Yes. And from a cost-of-service perspective, yes.

Q. And then am I correct that the recovery mechanism, how they're billed is based on monthly

demand or non-coincidental demand that's ratcheted at the 3CP level?

A. (Ferguson) Yes.

Q. So that's the part that's different in this particular case. And I guess the question I have ultimately is does it actually make a difference? I mean, is it just if -- you know, if the value is determined in the first step, how you recover it here would appear to fully recover that, if you've appropriately set the demand cost correctly; is that fair?

A. (Ferguson) Yes, subject to you will get that variability in those other classes ---

Q. Yes.

A. (Ferguson) --- because of differences between forecasts. You won't have that in this class.

Q. So more certain in this -- in the approach that you've taken here?

A. (Ferguson) Yes.

Q. Okay.

A. (Ferguson) And apart, Mr. Chair, it just recognizes that the demand of the customer ultimately will be dispatched by the company. So seems appropriate to just fix the charge.

Q. Right. And in the same way you can't determine the demand at system peak really because of the approach that you're taking and the influence from dispatch, you can't determine any of those monthly demands either?

A. (Ferguson) Correct.

Q. And is that -- does that issue play out in the differences as well between the cost of the interruptible credit between the two classes because of the assumption that it's being -- the NCP and the CP are essentially the same, that it's driving a significantly different amount than it is in the Large Industrial Interruptible rate?

A. (Ferguson) Could you just repeat

the question, please?

Q. I guess ultimately what I'm wondering about is this is the same issue? Like, if you've appropriately calculated the value of the credit, which I understand is being done at the same peaker base that says -- as the large industrial, is this, you know, the recovery of it, that $13, you know, whatever cents were -- that is also driven by the -- I guess the billing determinant side of things, which is assumed in this particular case, but ultimately does it matter, as long as you're -- you know, whatever you're using is recovering the value they've identified, does it make a difference?

A. (Ferguson) The cost foundation is the same, the value of a kilowatt of combustion turbine generation. The rest of the variance is attributable to the amount of forecast interruptible load on peak and the billing determinant as the divisor.

Q. Okay. All right. So both of those factors are influencing it?

A. (Ferguson) Yes.

Q. Okay. But ultimately, the rate itself -- talking about the $13 rate that Nova Scotia Power has indicated would be the one that was used if the model was followed -- would be recovering the value that is determined on the same basis as the large industrial customers?

A. (Ferguson) Yes.

Q. Going to take a look at the tariff language here for just a quick second.

THE CHAIR: Mr. Norwood, if we could turn up Exhibit N-1, please, and go to page 27? And I'm looking at the first paragraph in particular, Mr. Norwood.

BY THE CHAIR:

Q. I'm just curious as to how this actually works on the ground. So the last line in that paragraph says:

> The Company shall specifically identify in advance if any of the Customer's load is being interrupted pursuant to the terms and conditions of the Interruptible Rider in

accordance with those procedures rather than the Operating Procedure.

Does that mean that you have to tell PHP whether you're interrupting it before you -- say whether you're dispatching it down?

A. (Ferguson) Yes, that is correct.

Q. Okay. So then this concept of PHP riding through a dispatch-down direction and you being able to interrupt, does that actually work, given the language of the tariff? If you haven't told it in advance you're interrupting, instead you've told it you dispatched down, if they decide to ride through, is that option off the table for you, absent any system changes?

A. (Ferguson) Under the dispatchable rider of the tariff, PHP could be given an instruction to dispatch down, but as we've indicated, it's optional upon PHP whether they determine to ride through or not.

If they do choose to ride through, then -- and the system conditions did continue to -- if a capacity shortfall was on the horizon, they could be

interrupted at that point. So both provisions would apply.

Did I answer your question? Or could you repeat the question? Sorry.

Q. I guess this seems to imply that there's a specified order that you'll advise whether you're interrupting first, and then if you're not interrupting, there will be a dispatch schedule that they can follow. And absent any changes in the system, you know, having decided not to interrupt in the first place, are you kind of stuck with that if they choose to ride through?

A. (Willett) I think some of the nuance to this is the timing in which the schedule for a dispatchable rider benefit would be released. So as we discussed earlier, there are a number of times throughout the day in which Nova Scotia Power will provide PHP with schedules in order to follow. That would indicate, in the scenario you're describing, a tightening of the system due

to whatever generation availability, peak load. As that continues through, PHP's schedule would show them coming -- required to come down. If, in your scenario, Mr. Chair, they decide to run through, at which point the timing of the decision becomes more succinct, and I'll let Mr. Stanford correct me if I'm wrong, but the notification of the interruption is 10 minutes, I believe. So the DR is working in a way to ensure a reliable drop in PHP load for both parties. The interruption is an instantaneous event, or is near as instantaneous as possible.

But I'd defer to my colleague, Mr. Stanford, to correct if I got any of that timing incorrect.

A. (Stanford) No, that is correct. That interruption would have to occur within 10 minutes of the notification from the System Operator.

Q. So why was that particular sentence that I read included in the tariff? What purpose does it serve?

A. (Willett) Mr. Chair, I believe the language is -- sorry. I think the language is meant to distinguish between the two services. In particular, I think that the language itself is meant to provide PHP notice that they're not being dispatched down in accordance with the dispatchable rider, but interrupted.

Some context for that would be one of the examples that I provided, but also could be intra-hour as well. I think it's meant to clarify that this isn't a dispatchable rider or a dispatch; this is an interruption itself.

Q. Okay. So it's to make it clear that it is an interruption that they could be subject to penalties for? Is that ---

A. (Stanford) Yes. Yes, that is correct.

Q. Okay. Just on the energy charge now. So the evidence appears to suggest that the more recent forecast for load in 2027 will be lower than what

has been forecast to design the rate. Am I correct?

A. (Stanford) The evidence that PHP put forward in their evidence, but I would say that is continuously moving. So what was put in evidence a number of months ago is likely changed since that time as well.

Q. Okay. But that is the most recent evidence?

A. (Willett) That's the most recent evidence, but I have -- we have -- Nova Scotia Power has been providing updated forecasts in accordance with normal business with PHP.

Q. That vary from what has been presented in the evidence?

A. (Willett) Yes.

Q. Are you able to undertake to file the most recent forecasts you have from PHP?

A. (Willett) I believe so, yes.

Q. If you could do that, that would be Undertaking U-14.

UNDERTAKING U-14 - To file the most recent forecasts from PHP

BY THE CHAIR:

Q. In terms of setting the energy rate for the tariff as proposed in this particular proceeding, if the forecasted load is changed, the energy charge would change as well; am I correct?

A. (Willett) Yeah, I would say a number of things would change if you started to change the forecasted load -- the beginning point of developing a revenue requirement is understanding what the system requirements are. Fuel forecasts are built based on those; your fixed costs are based on those. And so it -- that's the beginning point and drives everything. But yes, to answer your question, if you had a different energy amount, and, you know, the same amount of -- well, actually, even in the cost of service, it would assign a different amount of costs as well. So it would change everything within what was done in the General Rate

Application if you started to change one component of the forecast.

Q. When you say, "It would change everything," would it have an impact on other rate classes?

A. (Willett) Yes, it would, because you would all of a sudden have -- you would have to do a complete new run of fuel, potentially, in order to say, "Well, before we ran fuel based on a certain total system requirements, and now we have a different system requirement," so you would need to be looking at what does that do to the fuel forecast, and then those costs are assigned to all customer classes. So it's not as simple as -- I would say it becomes challenging to change one aspect of a General Rate Application and say, "Well, this one component of things has changed, so let's make some modifications on that single component."

Q. So there's no way to isolate -- update the demand forecast and the energy rate, isolated

to just the proposed ELID Tariff to better reflect the recovery of fixed costs that might be expected at this stage?

A. (Willett) I think it would be difficult without having some very significant assumptions that would need to be made.

Q. Okay. And in terms of the PHP deferral that was approved in the General Rate Application, you -- as far as Nova Scotia Power is concerned, it not only covers changes in costs that might be driven by changes in what the Board actually approves, but also if the Board approves the forecast energy demand that Nova Scotia Power provided in its forecast is wrong, that the PHP deferral would extend to cover that as well? That's the company's position?

A. (Willett) Yeah, and what that discussion meant to cover was, you know, significant changes on the assumptions and specifically around Goose Harbour Wind. The company would understand normal volume

variances are likely to occur, and that wouldn't be expected to be a part of that, but if there was a significant material change in those load assumptions or of the Goose Harbour Wind, then that would be expected to be part of that deferral.

Q. And just finally a couple of questions arising from things that have come up already.

Just going back to the discussion, Mr. Mowatt, you had with Mr. Mahody about the value of RECs. As I -- in my notes, I thought you said at one point in that discussion that Nova Scotia Power didn't rely on the $22 value for RECs. Is that -- do you recollect saying that?

A. (Mowatt) I think, Mr. Chair, I was more referring to the PPA itself. The $22, it's not something that Nova Scotia Power would be targeting, in terms of a price, given the RES standards that we have.

Q. So curious, though, as part of the value exchange that's going on, implicit in the rate

design here, is -- are the RECs that Nova Scotia Power is getting valued to any extent?

A. (Mowatt) They wouldn't be included in any of the fuel costs that I would have been forecasting or any of that -- anything to that nature, no.

Yeah, so we wouldn't be explicitly modelling energy with RECs in the forecast. The previous RECs that we would have purchased would have been completed at the end of the year to ensure RES compliance.

Q. The discussion you had with Mr. Mahody, as well, with the forward replacement cost pricing, I just want to make sure I understand what you were saying there as well. I kind of got the sense you were talking about, when you referenced opportunity costs, that there was some ability to be more precise with the forward replacement mechanism or provide a more accurate price in the particular moment, versus trying to calculate it after the fact?

A. (Mowatt) If I gave that

impression, I apologize.

Q. You may not have. It might just have been me, so...

A. (Mowatt) The term -- I would have used "opportunity cost" as that's an alternative to replacement cost. It's the opportunity cost of the dispatch at that time. Nova Scotia Power would use proxy pricing at times to reflect cost of, say, solid fuel or coal because spot market doesn't necessarily exist, whereas with a gas unit, you can procure gas a day ahead and on the day which can adjust that cost. Similar with imports; you can have a day-ahead import or a real time import. So there's some nuance there with that cost.

The replacement cost methodology is a great example of the opportunity of dispatch and is different than, say, a total fuel cost at the end of the year when you have the ability to see how costs were procured, what you actually paid for them that hedges -- all of that kind of thing can go into that.

Does that answer your question, Mr. Chair?

Q. I think so. Thank you.

And then the last question -- I think it's the last question I have -- is just in terms of the end of the year for the dispatch rider credit, when you do the calculations of what the actual system costs were versus what the costs would have been at the levelized load, how is the wind that Nova Scotia Power receives from PHP wind treated in that analysis?

A. (Mowatt) Thank you, Mr. Chair.

So the wind would be the same in both scenarios. We wouldn't re-dispatch any intermittent generation, any renewable generation. Hydro would be -- we would just lock that in, and the only thing that would be allowed to vary would be your thermal units, based on availability, which you would have at the end of the year, imports to some extent. So the wind is the same in both cases.

Q. Okay. So PHP's ability to bank wind energy if it doesn't need it at any particular point in time is kind of irrelevant to that analysis?

A. (Mowatt) Correct.

Q. Those are my questions. Thank you very much.

THE CHAIR: I'll just go back around, just see if there's any questions arising from that.

I'll come back to Port Hawkesbury Paper, but Consumer Advocate?

Small Business Advocate?

MS. POWELL: No questions. Thank you.

THE CHAIR: Industrial Group?

MS. RUBIN: Just a brief follow-up I could ask from here, if that's okay?

THE CHAIR: Sure.

MS. RUBIN: All right.

FURTHER CROSS-EXAMINATION BY MS. RUBIN

Q. Mr. Ferguson, Mr. Melanson had asked the question about PHP qualifying for the large industrial rate, and I think you -- I'd say you kind of hedged your answer a bit. Can you confirm that the mill predecessor to PHP was on the LIIR rate at some point in its history, in the late 1970s?

A. (Ferguson) I'm afraid I can't. I would accept if you're telling me that that's true. There was a number of predecessors to these tariffs. But late 1970s? I can't testify. I'm just not sure.

Q. Can you accept that subject to check, as I'm drawing it from a presentation on interruptibility that I cannot put my finger on at the moment, but it was in the record.

A. (Ferguson) I can, yes.

Q. Okay. And then following that, it took a mixture of above-the-line and below-the-line rates?

A. (Ferguson) Yes.

Q. Okay. Including an industrial expansion rate?

A. (Ferguson) I think it is described as the industrial expansion rate at one time, yes.

Q. Okay. And then following that, we have the Load Retention Tariff and various bespoke tariffs for PHP?

A. (Ferguson) There were a couple of others, I think, in the interim, but, yes, for this purpose.

Q. And were the other ones above-the-line or below-the-line tariffs?

A. (Ferguson) Load retention, the ELIADC, of course, below-the-line. The ELIIR -- there was an Extra-Large Industrial Interruptible Rider one and two. There were sort of two versions of it. I think one of them had this notion of costing on an embedded cost basis,

similar to what we're proposing, but I'm just going from my recollection, I'm afraid.

Q. Right. Okay. Thank you.

And then just a follow-up question about the distinction between fixing the demand charge. Just I wanted to get a clarification on that. For -- so the demand charge for PHP is a fixed charge based on the assumed PHP 3CP demand contribution to the system, regardless of its consumption, behaviour and load factor through the year, is that right?

A. (Ferguson) That's what's proposed, yes.

Q. That's what's proposed. Right. And then but for the large industrial customers, the monthly demand charge, what's actually billed, isn't calculated in advance. The billing demand is the greater of the maximum demand recorded by the meter in the current billing month, or the winter peak ratchet, which is the maximum actual demand recorded during the preceding winter

peak, the December, January, February?

A. (Ferguson) Yes.

Q. Okay. And in addition, the Power Factor Correction clause that applies to the large industrial class applies to the demand; correct?

A. (Ferguson) I believe that's true. I don't have the tariff in front of me, but I believe it's true.

Q. Okay. There was a question about RECs being part of the value exchange in the rate design, and I think the response was that it's not costed explicitly, but the value proposition, am I correct that it's specified in the Regulation that you get the benefit of it, NSPI, so that you can count it towards achieving the Renewable Energy Standard?

A. (Willett) Are you referring specifically to the PPA, Ms. Rubin?

Q. Yes.

A. (Willett) Yes.

Q. And that's specified by the legislation; right?

A. (Willett) I believe so, but subject to check.

Q. Okay. So for all of those prescribed projects, NSP is allowed to count the renewable energy towards its Renewable Energy Standard, whether it's from EverWind or PHP?

A. (Willett) I'm not as familiar with those other PPAs as I would be with Port Hawkesbury Paper's. My understanding is that they are counted towards RES, but there is some nuance to how the load is reconciled, but I can't speak specifically to that.

Q. Okay. I wasn't speaking of the actual load. I was speaking of the value of it is assigned to you within the province to count it towards your Renewable Energy Standard, as opposed to monetizing it by selling it outside the province; correct?

A. (Willett) Yes.

Q. Okay. Thank you. Those were my questions.

THE CHAIR: Port Hawkesbury Paper?

MR. MacDOUGALL: Thank you, Mr. Chair.

FURTHER CROSS-EXAMINATION BY MR. MacDOUGALL

Q. Gentlemen, just to stay on the REC issue that was raised by Board counsel and the Chair, I'm not sure if this panel could answer these questions, we may need an undertaking, but are you aware that the Green Choice approval process is still ongoing in front of the Board?

A. (Willett) I am.

Q. And NSP is part of that process?

A. (Willett) I am.

Q. And NSP has provided comments in that process? Are you aware of that?

A. (Willett) I'll -- subject to check, but yes.

Q. And would you be able to indicate or confirm that NSPI has not challenged the renewable attribute loss rate as part of its comments in that process?

A. (Willett) I wouldn't be able to

do that, no.

Q. Could you take an undertaking as to whether NSPI has commented on the renewable attribute loss rate in the Green Choice PPA process before the Board?

A. (Willett) We can.

Q. Thank you very much.

THE CHAIR: That will be Undertaking U-15.

UNDERTAKING U-15 - To advise whether NSPI has commented on the renewable attribute loss rate in the Green Choice PPA process before the Board

BY MR. MacDOUGALL:

Q. And the Goose Harbour Lake Wind Project is not being built by Nova Scotia Power; correct?

A. (Mowatt) Correct.

Q. But at the end of the day, the

renewable attributes accrue to Nova Scotia Power; correct?

A. (Mowatt) Correct.

Q. And that allows you to avoid building other generation that may be required to meet your 80 percent renewable target in 2030?

A. (Mowatt) Correct.

Q. Thank you very much.

Mr. Ferguson, a couple of times again, both in response to the Chair and to Board counsel, you indicated -- I'm going to say these words, and you can tell me if they're wrong, that Port Hawkesbury Paper's load was highly volatile and dynamic?

A. (Ferguson) Yes.

Q. Okay. But is it fair to say that the load is highly volatile because NSP is dispatching the load?

A. (Ferguson) Yeah, volatile really isn't the best word. I really mean highly variable.

Q. Highly variable, okay. But Port

Hawkesbury Paper is only highly variable because it's being dispatched by Nova Scotia Power; correct?

A. (Ferguson) Yes.

Q. Okay. So -- and in fact you have indicated ---

A. (Ferguson) Well, I would just add, for the benefit of Port Hawkesbury Paper. So we are dispatching it for the benefit of Port Hawkesbury Paper.

Q. Sure, but the ADC, I think three or four of you gentlemen over time said, also creates system reliability and other benefits for the system as a whole that aren't particularly quantified?

A. (Ferguson) Yes.

Q. And in fact, I think you said earlier that a part of your rationale for the $500,000 for the priority interruptibility was to give some value to that flexibility?

A. (Ferguson) I did.

Q. And again, your evidence is in

fact, absent the ADC that is being dispatched by Nova Scotia Power, the mill would likely run generally flat; is that correct?

A. (Ferguson) Yes.

Q. Okay. Thank you very much.

MR. MacDOUGALL: Those are all my questions, Mr. Chair.

THE CHAIR: Thank you, Mr. MacDougall.

Mr. Mahody?

MR. MAHODY: No questions arising.

Thank you.

THE CHAIR: Any questions arising or re-direct, Ms. Power?

MS. POWER: No, thank you, Mr. Chair.

THE CHAIR: Thank you, panel. That concludes your testimony as part of this proceeding.

(WITNESS PANEL WITHDRAWS)

THE CHAIR: I think given the time, we'll just take our lunch break and pick up with Port

Hawkesbury Power witnesses.

Is that okay, Mr. MacDougall?

MR. MacDOUGALL: Yes, that's fine, Mr. Chair. And that'll also allow us to have one of the witnesses who is appearing virtually be ready to go as well.

THE CHAIR: Okay.

So it's 20 after 12:00. We'll come back at 20 after 1:00 and resume with Port Hawkesbury Paper expert panel.

Thank you.

--- Upon recessing 12:20 p.m.

--- Upon resuming

THE CHAIR: Okay. I think we're good to go.

Mr. MacDougall, am I okay to go ahead and affirm the witnesses? Or do you need -- wanted to do anything first?

MR. MacDOUGALL: No, I think that's

great. And then we can have them qualified after that, Mr. Chair.

THE CHAIR: Thank you.

I'll begin with Mr. Gorman online.

MICHAEL GORMAN, Solemnly Affirmed:

COLIN FITZHENRY, Solemnly Affirmed:

THE CHAIR: Mr. MacDougall, take it away.

MR. MacDOUGALL: Thank you, Mr. Chair.

Mr. Norwood, if we could pull up Exhibit N-2? That's the BAI direct evidence. And if we could go to Appendix A, which is the professional qualifications of Mr. Fitzhenry? There we go.

Mr. Chair, Mr. Fitzhenry's professional qualifications and expert testimony listing was filed as Appendix A to BAI's direct evidence, Exhibit A to N-2.

EXAMINATION ON QUALIFICATIONS BY MR. MacDOUGALL

Q. Mr. Fitzhenry, I don't want to go through all of the particulars in here, but would you be able to quickly give us a summary of your practice in the utility regulatory sector?

A. (Fitzhenry) Sure. I've been

employed at Brubaker & Associates for approximately 13 and a half years. Over that period, I've assisted consultants in various regulatory matters, including rate classes, you know, formula tariff modifications, system planning, procurement as well.

More recently, I've been serving as an expert witness for approximately four years. In doing so, I've testified in, I believe, 13 different states. I've also participated in Federal Energy Regulatory Commission settlement hearings.

I have a -- educational background, I graduated with a Bachelor of Science in General Engineering from the University of Illinois and I've participated in giving lectures at several of BAI's fall seminars.

Q. Thank you, Mr. Fitzhenry.

MR. MacDOUGALL: And if we could, Mr. Norwood, go to page 2 of Mr. Fitzhenry's professional qualifications?

BY MR. MacDOUGALL:

Q. And Mr. Fitzhenry, can you confirm that this is a list of regulatory proceedings in which you participated, in one manner or another?

A. (Fitzhenry) Yes, I can confirm. I would note that this was filed with my direct evidence. So to that end, you know, I've participated in several additional proceedings since this filing, but as at this time, you know, I've testified in well over 30 regulatory proceedings, approximately.

Q. Okay. Thank you very much, Mr. Fitzhenry.

MR. MacDOUGALL: Mr. Chair, based on Appendix A to N-2 and Mr. Fitzhenry's comments here this morning, I would ask that he be qualified as an expert in utility regulation and rate-making.

THE CHAIR: Any questions on qualification or objections from any party?

Thank you. He's so qualified, Mr.

MacDougall.

MR. MacDOUGALL: Thank you, Mr. Chair.

BY MR. MacDOUGALL:

Q. And Mr. Gorman, we're going to go through a similar exercise with you.

MR. MacDOUGALL: If we could pull up Appendix B now, Mr. Norwood? So it should just be the next document there. And Appendix B is the *curriculum vitae* of Michael P. Gorman.

BY MR. MacDOUGALL:

Q. And Mr. Gorman, could you give a brief overview of your experience in utility regulation, rate-making, and cost-of-service proceedings?

A. (Gorman) I will.

Good morning, Board. My name is Michael Gorman, and I've been with Brubaker & Associates since 1990, participating in regulatory proceedings concerning rate cases, integrated resource planning, various regulatory mechanisms investigated by the utility

companies. I've also been involved in special financing proceedings, such as securitization bond issuances on behalf of customers of utilities where the proceeds of those bonds were used to finance a specialized cost which were recoverable from customers and the use of the bonds was designed to lower cost to customers.

Prior to joining BAI, or its predecessor firm in 1990, I was with the Illinois Commerce Commission, having various responsibilities, starting off as a Resource Planning Engineer, moving into the financial analysis division, and ultimately assuming the position of Director of Financial Analysis for the Illinois Commerce Commission prior to joining BAI.

I've testified in well over 30 regulatory proceedings before the Federal Energy Regulatory Commission through three Canadian provinces and have offered written testimony before the Canadian Energy Board.

Q. Great. Thank you very much, Mr.

Gorman.

MR. MacDOUGALL: And if we could go to page 2 of Appendix B, Mr. Norwood? And if we could just go down a tiny bit so that we have the full part of the paragraph "Testimony Sponsorship"?

BY MR. MacDOUGALL:

Q. And I note here, Mr. Gorman, that -- I didn't count them all, but you have participated in regulatory matters in front of what I would suggest is a majority of the United States states?

A. (Gorman) I have, yes.

Q. And I also note that you have actually previously testified in Nova Scotia?

A. (Gorman) I have, yes.

Q. And my understanding was that that was before the predecessor to this Board, the Utility and Review Board, with respect to ROE matters; is that correct?

A. (Gorman) That is correct. Yes.

MR. MacDOUGALL: Mr. Chair, on the basis of Appendix B to Exhibit N-1, the CV of Mr. Gorman, and his comments made this morning, I would ask that he likewise be qualified as an expert in utility regulation and ratemaking.

THE CHAIR: Any objections or questions on qualifications?

Thank you, Mr. MacDougall. He's so qualified.

MR. MacDOUGALL: Thank you.

DIRECT EXAMINATION BY MR. MacDOUGALL

Q. Mr. Fitzhenry, I'm going to just take you through a couple of questions. In this proceeding, evidence was filed by BAI as Exhibit N-2; reply evidence was filed by BAI as Exhibit N-36; and BAI participated in responses to various of Port Hawkesbury Paper's IR responses. Is that correct?

A. (Fitzhenry) That's correct.

Q. Okay. And were those documents

prepared under your direction and control?

A. (Fitzhenry) Yes.

Q. And are they true, to the best of your knowledge and belief?

A. (Fitzhenry) Yes.

Q. And do you adopt them as your evidence in this proceeding?

A. (Fitzhenry) I do.

Q. And likewise, Mr. Gorman, do you adopt those written documents as your evidence in this proceeding?

A. (Gorman) I do, yes.

MR. MacDOUGALL: Thank you.

Mr. Chair, Mr. Fitzhenry has an Opening Statement.

And Mr. Fitzhenry, you can proceed to read that into the record.

MR. FITZHENRY: Thank you.

OPENING STATEMENT BY BRUBAKER & ASSOCIATES

MR. FITZHENRY: Good afternoon, Board Chair, Board Member, and counsel. My name is Colin Fitzhenry, and appearing with me virtually is Michael Gorman. We are regulatory and economic consultants with Brubaker & Associates, appearing in this proceeding on behalf of Port Hawkesbury Paper.

The matter before the Board involves Nova Scotia Power's Application to establish the Extra-Large Industrial Dispatchable Tariff. This tariff represents an essential transition for PHP from an incremental, below-the-line rate structure under the expiring ELIADC Tariff to a fully costed, above-the-line embedded cost-of-service tariff.

While we support this structural transition in principle, the proposed rate design and cost allocations filed by Nova Scotia Power, as well as the alternative proposals advanced by certain Intervenors, depart sharply from fundamental cost causation and non-

discriminatory ratemaking principles, resulting in a substantial over-allocation of costs to PHP.

Our evidence focuses on several cost-allocation and tariff-design elements required to ensure that the ELID Tariff produces just, reasonable, and non-discriminatory rates.

First, regarding demand-cost allocation, Nova Scotia Power proposes to apportion production and transmission capacity costs using an assumed 65-megawatt three coincident peak demand determinant, which combines 8 megawatts of firm demand and 57 megawatts of interruptible demand.

Under well-established cost-of-service principles, utility capacity is planned and built to meet peak demand. PHP's firm demand service is strictly 8 megawatts, while its interruptible load is served on an as-available basis. It does not drive generation or transmission capacity additions and is dispatched down or curtailed during periods of system constraint.

Consequently, allocating firm capacity costs based on a 65-megawatt demand determinant artificially inflates PHP's cost responsibility and its capacity cost allocation, and its capacity cost allocation should properly be based on its 8-megawatt firm contribution.

In this context, the Industrial Group's proposal to allocate demand using PHP's 120-megawatt annual average load represents an unjustified departure from standard ratemaking. Because the 3CP allocator is applied to every other above-the-line rate class, imposing a punitive average load allocator exclusively on a single industrial customer violates the statutory prohibition against unjust discrimination under the *Public Utilities Act* and must be rejected.

Second, with respect to the interruptible rider credit, if the Board adopts Nova Scotia Power's framework of charging PHP for 65 megawatts of capacity, cost causality requires that the 57 megawatts of interruptible demand be credited at Nova Scotia Power's

avoided marginal cost of capacity. The company's established methodology for pricing the avoided cost of peaker capacity yields an interruptible credit of $13.107 per kVA. Applying the General Rate Application settlement figure of $7.667 per kVA, which is derived from the distinct billing determinants of the Large Industrial Interruptible class, arbitrarily denies PHP approximately 4.2 million annually in avoided capacity value that its non-firm load provides to the grid.

Full crediting ensures firm ratepayers remain economically indifferent between adding peaking generation or avoiding capacity additions through interruptible service.

Third, addressing the revenue-to-cost ratio. Nova Scotia Power proposes an R/C ratio of 1.04373, requiring PHP to pay 4.373 percent above its allocated cost to serve. While R/C ratios above 1.0 are sometimes employed to mitigate cost-shifting among existing customer classes when rate changes produce

detrimental impacts to a specific customer class, PHP is entering an entirely new above-the-line class and has never previously been costed through the embedded cost study. Mandating an above-cost premium on a newly established class over-allocates costs to PHP without cost justification. For these reasons, the Board should instead adopt an equitable R/C ratio of 1.0.

Fourth, the ELID Tariff rates must be updated to incorporate PHP's 2027 energy forecasts, properly reflecting the upfront displacement of grid-supplied energy by the 168-megawatt Goose Harbour Lake Wind Farm. Aligning energy billing determinants with actual expected energy purchases upfront establishes accurate per-unit rates and avoids unwarranted distortions in cost recovery.

Finally, with respect to the dispatchable rider and priority interruptible service, BAI's evidence confirms that the operational energy shifting benefits under the DR, and the avoided capacity

reliability benefits under the IR, are separate and distinct. Because PHP absorbs a full embedded cost allocation under the ELID Tariff, 100 percent of the operational fuel and variable O&M savings generated by the mill's load flexibility should accrue to PHP, and diluting this credit through a sharing mechanism would undermine the customer's incentive to properly provide voluntary dispatch flexibility.

Similarly, compensating PHP with a 10 percent premium for priority interruptibility is fully justified because PHP accepts the highest-risk tier of forced curtailment, directly shielding other industrial customers and operating reserves from disruption.

In BAI's reply evidence, we directly address the alternative recommendations filed by other parties, which collectively depart from cost causation and impose undue burdens on the ELID class.

The Industrial Group's proposals, seeking to strip PHP of the interruptible and priority

credits, mandate physical operational control, and impose an asymmetric 120-megawatt average demand allocator, are discriminatory, punitive, and ignore the clear separation between the energy shifting dispatch and reliability curtailment.

InterGroup’s attempt on behalf of the Consumer Advocate to freeze PHP into an above-cost R/C ratio and force the Large Industrial Interruptible credit onto PHP disregards the explicit reservation of rights in the Settlement Agreement, relies on unrelated class billing determinants, and overlooks the fact that substantial fixed capacity costs are already paid by PHP through the energy charge.

Synapse's proposed reduction to the capacity credit to reflect PHP's revenue contribution applies a penalty not imposed on other interruptible classes, amounts to a negligible adjustment of approximately 3 percent, and fails to recognize that PHP’s direct high-voltage connection imposes no peak

transmission expansion costs.

Finally, Bates White's recommendations must be rejected because their call to recalculate the energy charge relies on a speculative 120 gigawatt/hour net load metric that they themselves concede is inappropriate for setting cost-based rates. Their proposed true-up mechanism infringes upon contractual billing rights under the approved Power Sales Agreement, and their rejection of the dispatchable rider undervalues a proven tool that lowers marginal energy spikes across the entire system.

Thank you for the opportunity to provide this Opening Statement. Mr. Gorman and I welcome any questions from the Board, Board Members, and counsel.

MR. MacDOUGALL: Thank you, Mr. Fitzhenry.

Mr. Chair, for efficiency purposes, because we have a panel that’s split with one gentleman here and one on the line, Mr. Fitzhenry will probably take

the lead on responding to most questions, but of course he'll ask his colleague, Mr. Gorman, when appropriate, if he has other things to add and Mr. Gorman, of course, will hop in when he thinks he has other things to add, but we'll probably take a run at Mr. Fitzhenry generally in starting to respond to the questions.

THE CHAIR: Thank you, Mr. MacDougall. That's helpful.

MR. MacDOUGALL: And he -- this panel is now available for cross-examination, Mr. Chair.

THE CHAIR: Nova Scotia Power?

MS. POWER: Yes, please. Mr. Chair. May I remain in my seat? Thank you.

Mr. Norwood, I want to go to Exhibit 2, please. It's the BAI evidence, at page 25. And looking at section 5, the Revenue-To-Cost Ratio, and starting on line 18.

CROSS-EXAMINATION BY MS. POWER

Q. The question is put to you, Mr. Fitzhenry:

> Is it appropriate to apply an R/C ratio greater than [one] to a customer transitioning from a marginal cost rate to an [above-the-line] tariff?
>
> And the answer is:
>
> No. Applying [an] R/C ratio greater than [one] to a customer transitioning from a marginal cost-based rate to an [above-the-line] tariff is generally considered inappropriate because it violates the fundamental regulatory principle of cost causality.

But Mr. Fitzhenry, when it comes to setting R/C ratios, is there generally a tolerance band?

A. (Fitzhenry) My understanding is that this Board has a tolerance band approximately between 0.95 and 1.05. What I would note is that in certain instances where that tolerance band has been adopted, it wasn't coming off a GRA where cost-of-service rates were recently re-examined for their appropriateness and cost-causation principles.

In addition, the -- PHP has not been costed under the previous cost-of-service studies. So when migrating from, you know, a previous embedded Cost-of-Service Study to the most recently approved Cost-of-Service Study, PHP didn't experience any, you know, positive or negative cost impacts from that migration, thus they didn't cause any, you know, positive or negative impacts from their -- that migration onto other customer classes.

Q. But Mr. Fitzhenry, you're aware that the Board approved the GRA based on the cost-of-service methodology with PHP as an above-the-line customer and the R/C ratio fixed at 1.04373; correct?

A. (Fitzhenry) My understanding is that the R/C ratio was not included in that Settlement Agreement.

Q. That wasn't the question. The Board approved the GRA based on PHP being modelled as an above-the-line customer with that R/C ratio set.

A. (Fitzhenry) I understand that the Board approved the Settlement Agreement, that's correct.

Q. Not the Settlement Agreement. The GRA.

A. (Fitzhenry) Oh, excuse me. Yes, the GRA. That's correct.

Q. Are you aware of how it came to be that Nova Scotia Power applied the 1.04373 R/C ratio to PHP heading into the GRA?

A. (Fitzhenry) I believe that R/C ratio was part of negotiations leading up to the GRA.

Q. Okay. And as part of your review of the evidence and preparing your report, is there anything more you learned about why Nova Scotia Power applied the 1.04373 R/C ratio to PHP?

A. (Fitzhenry) I don't recall.

Q. And have you independently assessed the impact on other customer classes of doing what you recommend, which is applying a 1.0 R/C ratio to

PHP's rate calculation under the proposed ELID tariff?

A. (Fitzhenry) I haven't assessed the individual rate impact to other classes.

Q. Thank you, Mr. Fitzhenry.

MS. POWER: Those are all my questions, Mr. Chair.

THE CHAIR: Thank you, Ms. Power.

Consumer Advocate?

(SHORT PAUSE)

MR. MURPHY: Good afternoon.

CROSS-EXAMINATION BY MR. MURPHY

Q. Good afternoon, Mr. Fitzhenry.

A. (Fitzhenry) Good afternoon.

Q. And Mr. Gorman online.

A. (Gorman) Good afternoon.

MR. MURPHY: Mr. Norwood, if you could bring up Exhibit N-1, Attachment 4? And I apologize, I don't have the page number for that. I might be able to find it. It's actually the -- it's the Settlement Agreement, so it might be ---

THE CHAIR: Page 30, Mr. Norwood.

MR. ROBERTS: Thank you.

That's great. That's good. Thank you.

BY MR. MURPHY:

Q. Mr. Fitzhenry, you're familiar with this document?

A. (Fitzhenry) Yes, I am.

Q. Okay. And I just want to note,

in the first recital there, recital A, it refers to, "Nova Scotia Power..., along with the Consumer Advocate..." And then it lists off a number of other parties. And the bottom kind of quarter of that paragraph, it says:

> ...and counsel for Port Hawkesbury Paper...have engaged in a collaborative process to reach consensus on a 2026 [to] 2027 General Rate Application...

And then if we can scroll down to recital E, it says:

> Throughout the process described in the foregoing, Customer Representatives were aided by their respective expert consultants, as each deemed necessary or appropriate.

Did you aid PHP through that process?

A. (Fitzhenry) I did.

Q. And in providing that aid, were you, I guess, involved in the development of the Settlement Agreement; and particularly, the terms relating to PHP treatment?

A. (Fitzhenry) I aided in the development of those terms, yes.

MR. MURPHY: Mr. Norwood, if we could turn to, it's page 6 of that document? Six on the bottom, so I think it would be page 36 or thereabout. Sorry; page 36 of the PDF. And if you scroll -- continue scrolling? Sorry; it's a few more pages. That's -- yeah. And keep scrolling through until -- at the top of the page, it says page 11 of 21. And then just scroll a bit further down. That's great.

BY MR. MURPHY:

Q. So you're familiar with each of these points that are enumerated here in (a), (b), (c), and (d)?

A. (Fitzhenry) Yes, I am.

Q. Okay. And when we look at (a), it talks about a:

> ...cost of service study [including] 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[st], 2026.

And then (b) says:

> The [cost of service] has been prepared on the basis of the following PHP load characteristics...

And then it -- we're all familiar with what the terms say there. But -- so would you have been aware at the time that this was being developed that these were the load characteristics that were going to be used by Nova Scotia Power to develop the Cost-of-Service Study that was filed with the GRA?

A. (Fitzhenry) Yes, that's my understanding as per this agreement.

Q. And the -- as we noted, or as we can see there, in Clause (b) it talks about PHP's firm load at 8 megawatts at the three coincident peaks, and then (c):

> PHP's firm, plus interruptible load, at a forecast of 65 megawatts based on prior actual PHP metered load at the time of NSP's 3CP...

And then (c), "PHP energy will be based on PHP's forecast usage for the test years..." And then I'm just going to continue on to the next letter

there, (c), where it talks about:

> The dollar value of the Interruptible credit to be applicable to PHP's Interruptible load shall be the same as the credit for Large Industrial Interruptible customers, plus the value of priority interruption service provided, if any. The priority interruptibility service that may be provided by PHP is modelled at an additional 10% credit.

And then we don't need to read it, but (d) talks about PHP and Nova Scotia Power developing something for the ADC to be used in this tariff as well, right?

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

Q. Okay. Now, in your evidence, we don't need to turn to it, but it's Exhibit N-2, and page 2 of that exhibit, you indicate that Nova Scotia Power's proposed design is imbalanced and overcharges PHP for its cost of providing service. And when you say Nova Scotia Power's proposed design, I just want to be clear, you agree that the design reflects what is in this PHP treatment provision, right?

A. (Fitzhenry) I would say that there's some similarities to the company's proposal to what's included in these terms. There has been some exceptions. For example, my understanding from company testimony today was that the 10 percent priority interruptible service may not apply under a different interruptible credit.

In addition, my understanding is that the way that the company characterizes 65-megawatt demand determinant is not based on the 3CP. So I would say that the company's proposal, the ELID Application, follows some of these subparts here, but not in their entirety.

Q. And as far as your own proposal, which would be PHP's proposal, fair to say it differs significantly on a few different points, right?

A. (Fitzhenry) I would say that we -- you know, our proposal largely, you know, is aligned with most of these subparts, but there is some deviations as well, yes.

Q. Okay. And the first deviation would be firm service capacity charge should be based on 8 megawatts of firm demand at 3CP and not firm plus interruptible at 65 megawatts?

A. (Fitzhenry) Well, again, if we look at what you have on the screen here, subpart (b) -- (a) of subpart (b), it says, "PHP's firm load at 8 [megawatts] at the three coincident peaks;..."

Q. Okay. But what you're espousing, though, is for -- I'm more referring to (b), which talks about "PHP's firm, plus interruptible load, at a forecast of 65..."

A. (Fitzhenry) Right. So we have, you know, two proposals that we've, you know, put before the Board for your consideration. The first of which would be PHP's firm load at 8 megawatts, and that would be their frequency in a peak and how their -- would be their demand allocation.

And then an alternate recommendation

as well, where we said, you know, we -- under the condition that the 3CP would be billed at a 65-megawatt determinant, that PHP be provided with 57 megawatts of interruptible credit under the assumption that it be valued at -- using PHP's billing determinants, and not the billing determinants of another class.

Q. Okay. And that's where we get the 13.107 kVA instead of the seven dollars and change that ---

A. (Fitzhenry) That's my -- according to the company, my understanding is that if -- had PHP's billing determinants been used to calculate that credit, it would have been $13, approximately $13.

Q. Okay. And then the last point, which my friend from Nova Scotia Power had asked about, was the cost of service should be set at 1.0, that would be the next point. And then the last would be to use updated energy forecasts?

A. (Fitzhenry) Correct. Are we

still talking about the Settlement Agreement, or are you just talking about our proposal in general?

Q. Your proposal, yeah.

A. (Fitzhenry) Yes, our proposal in general in proposing a 1.0 R/C ratio and the -- I'm sorry; I forgot the last point already.

Q. Updating the energy forecast.

A. (Fitzhenry) That's correct, updating the energy forecast. Thank you.

(SHORT PAUSE)

BY MR. MURPHY:

Q. Okay. To start with the proposal on the -- using the 8-megawatt hours instead of the 65, I understand that if the Board adopted this recommendation, PHP's costs would be reduced?

A. (Fitzhenry) That's correct.

Q. And do you know by how much their cost would be reduced?

A. (Fitzhenry) I believe there is an

IR response that was discussed by the company that estimated that to be approximately $9 million.

Q. Okay. And I guess -- I think I know what you're referring to.

MR. MURPHY: If we could go to N-15, IR-2? Yeah, sorry, you had it there. Back to that -- there was a table. Yeah.

BY MR. MURPHY:

Q. Okay. Is this what you'd be referring to?

A. (Fitzhenry) Yeah, this is the table I'm recalling.

Q. Okay. And is it your understanding that if PHP's costs go down, they don't just evaporate, they're going to be assigned to other customers?

A. (Fitzhenry) I don't know. I don't have a proposal for how those costs would be reassigned. I know the Settlement Agreement does include

a deferral mechanism. I'm sure there's other regulatory mechanisms available to the Board potentially as well, but I don't have a proposal for how those costs would be reassigned, or if at all.

Q. Okay. So if they weren't reassigned, are you suggesting that Nova Scotia Power would simply absorb those costs itself? Or how -- what's to happen there? Because their revenue requirement would be fixed, right?

A. (Fitzhenry) Right. So referring to -- assuming that, I guess, the 2027 -- you know, looking at 2027 exclusively and not 2026, and assuming that the rates would go into service January 1st, right, so let's say under that specific circumstance where there wasn't a deferral mechanism deployed, in that instance, unless there was, you know, other known immeasurable changes to the company's 2027 revenue requirement, then, you know, on a forecasted basis, those costs would have to most likely be, you know, reassigned or recalculated and

recalibrated to other classes.

The Board could also, you know, consider just again other regulatory mechanisms to, you know, hold those costs, either through their deferral mechanism, you know, and then reassess how to apply those costs in a future test year as well.

Q. But so -- and I take your point; you don't have a particular proposal on what should happen to those costs, but you acknowledge that those costs will have to be dealt with by Nova Scotia Power and the Board in some fashion?

A. (Fitzhenry) It would have to be dealt with. Not necessarily reassigned to other classes. Again, there's -- I think the Board has a lot of discretion with how to address that issue.

Q. We don't necessarily need to turn to it, but it's in the evidence and Nova Scotia Power's response to SBA IR-1(b), where they indicate that:

> The firm load of 8 [megawatts for PHP] is estimated based on historic hourly minimum

loads for the PHP plant.

But then they go on to say that:

> The minimums depend on what operations are occurring at the PHP and the status of operations [at] the PHP Biomass...generating facility, with which it shares some station services. Minimum PHP loads between 8 [megawatts] and 12 [megawatts] have been the values most frequently observed; however, minimum loads of 15 [megawatts] have also been observed when PHB is in operation to ensure the reliable operation of that generation resource.

Do you have any reason -- if you'd like to pull it up, we can, but do you have any reason to disagree with that statement?

A. (Fitzhenry) Could you say again? That was a PHP response to an SB -- can you clarify for me the number?

Q. Yeah, it's Nova Scotia Power Response to SBA Information Request 1(b), and that is Exhibit 9.

A. (Fitzhenry) I would suggest that, you know, the operating characteristics of PHP at times

of, you know, minimum demand would be primarily better addressed by, you know, PHP witnesses, as opposed to BAI witnesses.

Q. Is it your understanding that 65 megawatts is the average of PHP's historical already dispatched load based on certain years?

A. (Fitzhenry) My understanding, that is -- that's approximately the average 3CP demand average over a two-year period, 2022 and 2023.

Q. And did you hear the testimony yesterday from when counsel for PHP was questioning the Nova Scotia Power panel?

A. (Fitzhenry) I did.

Q. Okay. And he referred to more recent numbers; I believe it was 2024 and 2025. And I think that the average that came out of that was 28 megawatts. Does that sound about right?

A. (Fitzhenry) That's what I recall as well.

Q. Okay. Which is still more than the 8 megawatts that's being proposed?

A. (Fitzhenry) That's correct. What I would suggest is that, you know, the 65-megawatt 3CP demand, you know, average over '22 and 2023 period, and then subsequent lower, you know, 3CP demand over the '24 and 2025 period could potentially suggest, you know, a tightening of supply demand constraints. So if anything, if that trend continues, then we would likely see, you know, a continued decline in that 3CP demand, especially if the company elects to dispatch, you know, PHP down or, you know, interrupt the -- PHP at the times of those three coincident peaks. And that could very well be likely if the system continues to see the supply demand balance, you know, be more and more constrained over a long period of time.

Q. Is it -- am I understanding correctly; Nova Scotia Power can request that PHP dispatch down, but PHP can also voluntarily do it on its own,

right?

A. (Fitzhenry) It's capable of doing that. It certainly would be more likely or more inclined to do so if it was given, you know, certain price signals or certain signals to do that, either through, you know, the required interruptibility that they're required to do, or again, under the dispatch codes.

Q. And this may -- again, this may be a question for PHP, but do you have any basis to dispute the evidence that the swinging coincident demand for PHP ranges from 8 megawatts all the way up to 160 megawatts?

A. (Fitzhenry) Over what period?

Q. Not necessarily -- I don't have it in front of me, what the evidence would say, but I think it's in your evidence, so maybe ---

A. (Fitzhenry) So you said coincident demand? Or are you talking about the operational, you know, load, the hourly loads?

Q. Sorry, the:

> ...PHP peak period demands could range between a low demand of 8 [megawatts] and a high demand of 160 [megawatts].

And that's at page 5 of your evidence.

MR. MacDOUGALL: Mr. Chair, for the remainder of these questions, if I could maybe ask my friend if he could pull the documents up in advance? That would be very helpful.

MR. FITZHENRY: Yeah, at page 5, lines 2 through 4, we say here that:

> NS Power acknowledges that PHP peak period demands could range between a low demand of 8 [megawatts] and a high demand of 160 [megawatts].

So I would note that there's no, you know, mention of coincident demand there.

BY MR. MURPHY:

Q. Okay. And I guess, you know, when it comes to 3CP, you know, my understanding is the purpose of using that methodology for cost allocation is that it's intended to sort of, you know, capture customers

and their use of the system on the most, you know, demanding days of the year. Is that your understanding as well?

A. (Fitzhenry) Yes, I would largely agree with that characterization.

Q. Okay. And isn't the purpose of it to sort of provide a snapshot so that it provides a real picture of the customer's demand?

A. (Fitzhenry) The purpose of it is to allocate costs, primarily through the Cost-of-Service Study. So in that sense, through the -- you know, Settlement Agreement and the GRA process, the parties, you know, and the Board, through their approval, have made a determination that the CP3 demand allocator is the appropriate methodology for estimating customer contribution -- customer class contribution to production capacity costs and transmission cost.

Q. And I guess it's a rough tool, right? Like, it doesn't -- it doesn't necessarily -- you

know, the company doesn't dig into all of the data to show exactly what every customer and every class is doing over the course of the year to come up with 100 percent accurate depiction of each customer's demand, right? It's just one way of trying to figure it out. It's a well-accepted way, but it's just one way of trying to figure out what that demand is, right?

A. (Fitzhenry) I would acknowledge there's other cost allocation methodologies.

A. (Gorman) Yeah, I would add that the coincident peak typically is used both for system resource planning, as well as assessing how each of the respective rate classes contribute to those system peaks. So it's used for both the purpose of resource planning and for cost allocation.

Q. But I guess if the point is to, you know, understand each customer's contribution to system costs, then wouldn't you want to use a figure that was reflective of actual usage, as opposed to, you know, a

figure that may artificially depress or increase an impression of somebody's demand?

A. (Fitzhenry) I would say that the 3CP demand is an estimation of customer usage at times of peak demand.

Q. But you heard the Nova Scotia Power panel today, right? And they had indicated that there are certain customer classes where there's going to be more than one customer in the group, and so they can -- you know, some people may be low on that coincident peak day, others may be higher, and they can rely upon the -- you know, the aggregate to come up with something that they consider to be a reasonable reflection of what the group would be. It's different when you have one customer who potentially, you know, could intentionally move its demand down on, you know, the coldest days of December, January, and February, and then sort of game the system.

A. (Fitzhenry) I would say that, for one, the -- you know, PHP is largely being dispatched by

the company; again, NS Power. They're given certain price signals. Or maybe they're not given certain price signals. That's really kind of up to the company to send those signals to PHP. Also, they could interrupt PHP. But that's, again, up to the company, to whether or not they're going to interrupt PHP.

I acknowledge that it's -- the ELID is represented by a single customer, whereas that's not the case with other customer classes. But again -- yeah, is that responsive to your question?

Q. I guess so. I guess I ---

A. (Gorman) Well, let me add to that. I mean, the reason you use more than one coincident peak, you know, a 3CP versus a 1CP, is for the very reason you described; customer's contributions to those peaks can vary at different points in time. So use of a 3CP, to the extent that describes the peak period of the utility, provides a normalization of each of the customer classes' contribution to that system peak. And whether or not a

specific customer could game the system, they'd have to know when that system peak will occur. Nobody knows that until after the fact. So from a practical matter, you know, number one, it's almost impossible to game it because you don't know it until after it occurs, and number two, there's going to be production cost impacts on a company that tries to game the system and reduces production because there's going to be a loss of operating revenue for that company.

So whether or not it makes economic sense for anybody to try to do it is a real question because of those factors.

Q. And that's fair. And I guess -- you know, I guess the point that I'm trying to get at here is if the purpose 3CP is to take a snapshot of demand, then, you know, there's going to be some variability in other classes because there's more than one customer. But where you have one customer and it's a customer who can be dispatched down, then is that sort of artificial and not

actually achieving what 3CP, and sort of a rigid application of 3CP, would be intended to achieve?

A. (Fitzhenry) I would say no. I mean, I largely disagree. I mean, there's, you know, many instances of different types of classes with different class characteristics. I can think of, you know, specific -- in some jurisdictions, there's specific domestic classes with behind-the-meter solar generation. Certainly if it's a summer peaking utility, that solar generation is going to provide a benefit to that customer class, and it's due to their capital investment they made in that solar generation that they deserve that benefit to be flowed through to their Cost-of-Service Study.

So yeah, no, I would say I would disagree.

A. (Gorman) I would add to that I also disagree with it and, you know, from a system resource planning, to the extent the three coincident peak actually includes interruptible load, then the utility

could make adjustments to that actual measured 3CP to adjust it down to what its firm peak application is for resource planning. And to the extent that helps to avoid making additional investments in production resources, there will be a savings to the utility.

From an operating perspective, if the utility dispatches that same customer down during those system peak periods, that has the effect of improving system reliability and probably also stabilizing the power quality of the system during those strong peak periods.

A. (Fitzhenry) And the customer is -- you know, there's a cost to its interruptibility as well, so...

Q. Do you accept that transmission costs are driven by both interruptible and firm load?

A. (Fitzhenry) No. I understand -- I listened to the company's testimony with respect to this issue, but my understanding is that, you know, power flow modelling is often done with -- when looking at the bulk

transmission system., it's often done with a minus one contingency, which means that when studying this, you know, the utility assumes that, you know, one large transmission line would be out, and evaluating whether the system could still be served and whether or not the company has, you know, leverage interruptibility to serve to -- as a result of, you know, a transmission outage. That's still a tool they have. So yeah, with that respect, I disagree with the company.

A. (Gorman) Yeah, if I could add to that, because I also disagree with it. You know, I would acknowledge that the interruptible credit under the alternative proposed design for the ELID designs a credit that only relates to production, resource of cost avoidance, but the ability to interrupt can provide system stability in the face of either reduced production capacity available or transmission constraints which may otherwise result in failure of the company ability to meet the demands of their firm customers on the system.

So the benefits relate to both system constraints that can be caused by either reduction in adequate production or transmission capacity.

Q. I'd like to move on to the value of the proposed interruptible credit, which I understand you're indicating that if the Board accepts the use of firm and interruptible for 3CP, that the interruptible credit should use the Nova Scotia Power standard formula, right?

A. (Fitzhenry) That's correct. That's the alternate proposal.

Q. Okay. And as far as Nova Scotia Power's justification for including it, the, you know, evidence would seem to indicate that it's because that's what the Settlement Agreement says, right?

A. (Fitzhenry) Yes, I largely agree that's their response.

A. (Gorman) And it represents the current marginal cost to peaking capacity that is avoided

by the ability to interrupt customers.

Q. So the -- I guess you would agree with me that in any settlement there's going to be puts and takes, right, where some parties agree to things and maybe give up some other position that they were hoping to achieve?

A. (Fitzhenry) I'll agree that settlements are often compromises.

Q. And there's usually going to be trade-offs in that process, right?

A. (Fitzhenry) Potentially.

Q. And if -- you know, would you agree with me that you could look at most Settlement Agreements and find one or two elements that are debatable, but on the whole, if it's a component of the settlement, then, you know, that's a reason to sort of leave it be?

A. (Fitzhenry) I guess that would be a possibility. I think it would have to be depending on

the issue and the term and the importance of that to the individual party involved.

Q. Well -- and I understand that PHP is taking a position on as to why it's not bound by the terms of the settlement, but in a normal course, you know, if we ignore that aspect of PHP's position, if you have a settlement, there might be components of it that you could debate based on ratemaking principles, let's say, but if it's part of the settlement, you're not going to start picking apart one element because you don't know what it may link to as part of the overall settlement, right?

A. (Fitzhenry) I'm not sure I'm really following this line of questioning. Could you maybe rephrase the question?

Q. Well, I guess if we -- let's assume that it is a Settlement Agreement. That's debated, right? And we acknowledge PHP is debating that issue. But let's say the Board finds that it is a Settlement Agreement. The fact that one element may be hard to

justify, applying, you know, normal ratemaking principles, that wouldn't be a basis to dig into the settlement and start making all kinds of changes, would it?

A. (Fitzhenry) I mean, I would say that if the settlement has been adopted by the Board, that's the recognition that the settlement is reasonable, I guess.

A. (Gorman) I would add that, yeah, there could be different offsetting balances, including the settlement, such as, for example, measurement of interruptible credit and the ability for a specific cost or consideration later. So there can be the ability to restructure the settlement in a way that all parties are still made whole but ensure that everybody is treated fairly within the settlement.

MR. MURPHY: Mr. Norwood, if you could turn to Exhibit N-8? And it is IR-4. I believe it's page 6 of the document. If you could scroll down to question (c)?

BY MR. MURPHY:

Q. So there it says:

> Please provide the reduction in allocated costs to PHP in each of the 2026 and 2027 if the interruptible credit independently developed for PHP is used as opposed to the interruptible credit calculated for the LIIR.

And I would note that these are NSPI responses to PHP information requests.

MR. MURPHY: If you can scroll down to the answer?

BY MR. MURPHY:

Q. And there it says:

> The reduction in PHP's annual costs is...4.2 million in the 2026 and 2027 test years if the interruptible credit independently developed for PHP is used as opposed to the interruptible credit calculated for the LIIR.

And so similar to my question about what happens to those costs, I guess would you have the same answer that that's -- they're going to have to be allocated or dealt with in some way by NSP and the Board?

A. (Fitzhenry) Yeah, generally, you know, any sort of deviations from what was included in the GRA is going to require some adjustments. I would note, I think, you know, this is the proper forum and process for ensuring we get the ELID Tariff right. That's why we have this process; that's why we have the settlement term that specifically allows for debate of these provisions for the ELID Tariff in this proceeding. So while I understand there'll be, you know, other impacts to making adjustments, I think the -- what's of most importance is ensuring that we develop a cost-based rate that's based on cost-causation principles in this proceeding.

Q. Do you agree that if PHP had taken the positions that are being put forward in this Application at the time of settlement, that this could have impacted how other parties viewed that settlement?

A. (Fitzhenry) I would imagine that sort of any change in position would have to be considered by other parties.

Q. Right. You know, so I think you said it was 5 million for 2027 for the first item there on the 3CP, and now it's 4.2 million, based on the formula for the interruptible credit. So again, all of that is dollar values that would -- are necessarily going to be shifted to other classes, but do you -- I guess, would you agree that those are material changes?

A. (Gorman) I don't know if we acknowledge that they would only be shifted to other classes. They may be spread over all rate classes based on repricing of the production and transmission costs. There may be some shifting of costs, but not necessarily all of them.

A. (Fitzhenry) And I would note that those wo figures, whether it's the revision of the interruptible credit or the 8-megawatt firm demand, they're not compounding. We are -- it's an either/or proposal that we're making in this -- with respect to our testimony.

Q. And what happens to the 2026 values? I guess those are now considered a wash at this point; they're going to be allocated to other customers?

A. (Fitzhenry) What do you mean by allocated to other customers, the 2026 values?

Q. Well, there's money that's accruing in a deferral account that was created for kind of in the meantime until this issue was resolved. And so if -- however this -- if the tariff ended up following the parameters that PHP proposes, am I understanding that -- it's not like it's going to be retroactive, right? Like, the values for 2026 are already in that deferral account and will have to be dealt with?

A. (Gorman) I think the Commission has yet to determine how it's going to treat those deferral costs. So that would necessarily be after the year the deferrals were made, or deferrals are recorded.

Q. On the revenue-to-cost ratio, I understand what your position is on that. The 104.27

percent, it's -- that's equivalent to the R/C ratio for all other classes except the domestic and the small business, right?

A. (Fitzhenry) That's my understanding.

Q. Okay. And you would agree that a new customer who comes in under any of those existing rates, that's going to be the R/C ration for that rate, even a new customer who had no prior involvement or contribution to that rate?

A. (Fitzhenry) Yes, that's correct. If the new customer is not taking the ELID Tariff and taking one of the other rate schedules being provided by the company, then whatever the R/C ratio that was applicable to that rate class, they would also be included in their rate as well.

Q. I just want your response on this comment that the Industrial Group -- counsel for the Industrial Group made in their opening statement, where

they sort of questioned the -- or indicated the principles of ratemaking prevail over whether any particular customer believes their tariff or rate is satisfactory. Would you agree with that?

A. (Fitzhenry) Could you please show it on the screen?

Q. Sure.

MR. MURPHY: It's Exhibit N-43 and it's on page 1, line 32.

BY MR. MURPHY:

Q. So you can read -- if you read the paragraph, line 27 to 32.

A. (Gorman) I'm sorry, can you repeat your question related to this statement again?

Q. Yeah, I'm just asking if you agree with this statement?

A. (Fitzhenry) With the statement being:

> It should not have bargaining power extended to it to negotiate terms it considers

'satisfactory'?

Q. Yeah. And the lead up to that, essentially, you know, what the Industrial Group is saying, that the tariff should be:

> ...a principled tariff grounded in the foundational tenets of ratemaking -- above all, cost causation -- consistent with the treatment of other Above-the-Line customers. PHP should be charged for the costs it causes the system, with appropriate credit for genuine load-shifting benefits it provides, and no more. It should not have bargaining power extended to it to negotiate terms it considers 'satisfactory'.

A. (Fitzhenry) I agree that the tariffs should be based on cost causation, consistent with the treatment of other above-the-line customers. PHP should be charged for the cost it causes the system, with the appropriate credits for load-shifting and interruptible benefits. I disagree with the characterization that PHP has some bargaining power to negotiate, you know, some special terms to its satisfactory -- to its satisfaction, I guess.

A. (Gorman) Yeah, I would add, I

believe this is the proceeding which we're trying to design an ELID Tariff that meets those objectives.

A. (Fitzhenry) That's right. And all parties have the ability to participate in this proceeding and provide their evidence to the Board.

Q. Okay. So it wouldn't be your position that the Board should try to cater to PHP to come up with a tariff that it will deem acceptable or satisfactory?

A. (Fitzhenry) Absolutely not.

A. (Gorman) But we believe PHP should be giving due process in advising the Board on what tariff design meets these objectives.

MR. MURPHY: Those are all my questions. Thank you.

THE CHAIR: Thank you.

Small Business Advocate?

CROSS-EXAMINATION BY MS. POWELL

Q. Good afternoon.

A. (Fitzhenry) Good afternoon.

A. (Gorman) Good afternoon.

Q. I'll be looking mainly at you and looking at Mr. Gorman electronically, or at least in my mind. Thanks.

MS. POWELL: Mr. Norwood, if we could just bring up Exhibit N-2, which is your evidence, looking at PDF page 4 of 34. And this is at page 2 of the document itself.

BY MS. POWELL:

Q. You mention here, this is down on lines 23 to 25, you state in your evidence:

> The interruption demand service will not impose resource capacity cost on [Nova Scotia] Power because this demand will be served only on an as-available basis.

So does that mean when you speak about it -- you refer to the 57 megawatt as interruptible load that is served on an as-available basis, so if NSP wanted

to not serve PHP, they're allowed to state that that additional energy is not available and not provide it?

A. (Fitzhenry) NSP is allowed to interrupt PHP down to its firm megawatt level -- firm 8-megawatt demand level.

A. (Gorman) Yeah, I think the question is more of when capacity is not available to serve the interruptible load, they would have the right not to.

Q. And just jumping to another part of your evidence just to clarify, so if PHP -- we've been talking about the ELID and what would happen if you -- the tariff was approved, with or without the recommendations from yourselves or others, but if PHP was taking load under more typical large industrial tariffs -- I just wanted to ask you a question about that -- would the appropriate 3CP load determinant still be the ones identified when the ELIADC was in effect?

A. (Gorman) What do you mean by

"typical" tariff?

A. (Fitzhenry) Yeah.

Q. So I guess a different -- like, a typical not specific to PHP, but the large industrial tariff. If you -- if we end up with neither an ELID or a revamped ELA -- IADC, sorry; I'm getting -- so if you are going forward with another large interruptible tariff, I guess would the appropriate 3CP load determinant be what's been used before the ELIADC, or how would -- we've heard evidence from NSP how they would approach that. I'm asking how you would approach that.

A. (Fitzhenry) So just to clarify, I don't think that there's been a three-megawatt CP used in the development of the ELIADC. I could be wrong. Okay? But if your question is that if PHP was served on the LIIR and they were in that class, right, then the 3CP would be based on whatever test period's being evaluated, the 3CP of that class.

Q. So not the 65 megawatts?

A. (Gorman) Well, you know, I think what we're asking -- we're kind of outlining an analysis that we haven't yet performed. You know, because we're measuring cost of service based on the terms and conditions of this tariff, and this tariff contemplates a level of firm service and a level of interruptible service when the system resource capacity is available to serve the interruptible load.

If we're talking about a different kind of service, then that would necessitate a review of whether or not NS Power is able to offer that service to PHP, and if it is, then what its cost of providing service under that rate would be. And I don't think we've taken a detailed look at that. What we've measured is this proposed combination of firm and interruptible service to PHP.

MS. POWELL: Thank you, Mr. Gorman. That's helpful.

Just wanting to clarify, as I go

forward in your evidence.

MS. POWELL: So staying in that Exhibit N-2, sub (2), Mr. Norwood, but if we could just go down to the next page? So we're looking at lines 6 to 8 on that page. This is page 3 of your document and page 5 of the PDF.

BY MS. POWELL:

Q. Six (6) to 8, you say:

> If the Board prefers NS Power's proposed design of the ELID, albeit not being cost based, it should be adjusted to reflect NS Power's cost of servicing PHP.

I just wanted to ask you about the clause which says, "not being cost based". So you refer to NSP's proposed design not being cost based. What part isn't? Can you just elaborate on that; what part do you mean when you're saying it's not cost based?

A. (Fitzhenry) Well, I mean, I think just for one example, I think the interruptible rider, you know, being valued at the LIIR class, you know, using the billing determinants of those classes to make a

determination about the per-unit interruptible credit being applied to the ELID class, I would suggest that that's not a cost-based ratemaking decision.

Q. And in terms of when you determined that it wasn't cost based, was that obvious to you right from the beginning or was there a certain time when it became aware that it wasn't cost based or it was being developed that wasn't cost based?

A. (Gorman) Say we reached that conclusion after we complete our evaluation of the company's proposal and reviewed other documents to make assessment of whether or not we thought it was reasonably aligned with what their cost of providing service is.

Q. Thank you.

MS. POWELL: I'm just looking -- my friend has asked a few of the questions I was going to ask, so I'm just going to, in the interest of moving us forward, if you just bear with me for a sec?

BY MS. POWELL:

Q. I did want to ask you a couple of questions, back to the R/C ratio. So if we look at -- we're still in your evidence, Exhibit N-2.

MS. POWELL: And I'm just going to find the page reference, if I may, Mr. Norwood. One second. Yeah, so just to give you the reference, it's found on PDF pages 27 to 28 of 34.

BY MS. POWELL:

Q. So this is pages 25 to 26 in your paper copies, if you're looking at the paper copies. And this is where you talk about the revenue-to-cost ratio.

Just wondering, in your -- you sort of lay out your opinions, but what's the fundamental purpose? You talk about shifting of the R/C ratio from 1.0 for a rate class to something above 1.0. So can you just walk me through that?

A. (Fitzhenry) Could you just restate the question?

Q. Sure. What's the fundamental

purpose of shifting the R/C ratio from 1.0 for -- to -- for a class to something above 1.0?

A. (Fitzhenry) So in most instances, it's to use this principle of gradualism. So the principle of gradualism states that when you have an embedded Cost-of-Service Study, and this often happens during a rate case where adjustments are made to that Cost-of-Service Study that have an undue impact on maybe one or more classes. As a result of that, there could be potential rate shock. So rate shock would be, as you know, a significant increase in rates above the rates they were previously set.

So what will often be used in the instance of setting an R/C ratio other than 1 in those instances is that if a certain class is experiencing rate shock due to, you know, undue -- an undue burden as a result of a change in Cost-of-Service Study, often a Commission or a Board will adopt that principle of gradualism and note that, you know, with a goal of

eventually achieving a 1.0 R/C ratio, but in this instance, we will deviate from that 1.0 ratio in order to ensure that a specific class doesn't have an undue financial burden and is not experiencing rate shock.

Q. So in terms of these principles that you've just described, why would those not apply to a new tariff as well?

A. (Fitzhenry) Well, a new tariff doesn't -- isn't a full rate case, so it's not, you know, making observations about the cost-of-service of other classes, just the particular class that's under investigation in the tariff proceeding.

Q. And you may have touched on this already, but I just wanted to clarify. On page 26, and maybe I'll pull it up, so you get the context of this remark.

MS. POWELL: Sorry, my apologies. I'm in document page 26, so I mean page 28, Mr. Norwood. My apologies. And we're looking at lines 2 to 4. So at the

top of the page, if I may. Yeah.

BY MS. POWELL:

Q. You talk about, in this sentence:

> While this is sometimes done for residential protection, applying it to a customer already undergoing a structural shift to a full-cost tariff creates an inequitable 'double hit.'

Can you just explain to me what you mean by that "double hit"?

A. (Fitzhenry) Right. So a particular class wasn't be served under an ATL rate but is being transitioned to an ATL rate that's also experiencing an R/C ratio, so that's being allocated costs above its cost-of-service, could potentially be experiencing, you know, cost increases due to that transition from a below-the-line to above-the-line rate. And in addition, be experiencing, you know, an additional rate increase as a result of that R/C ratio above 1.0.

Q. Earlier in your evidence, your written evidence...

MS. POWELL: So we're going back to page 3, which is PDF page 5 in Exhibit N-2, Mr. Norwood.

BY MS. POWELL:

Q. We're still talking about R/C ratios. So just following along from there. If we look specifically at lines 29 to 38, around where we're talking there, there's discussion there of R/C ratios, and you've mentioned a little bit about why different numbers would be applied, other than 1.0, and you referred to R/C ratios being employed to mitigate cost shifting among existing customer classes when rate changes produce detrimental impacts to a specific customer class. And so is -- I just want to clarify, is the evidence that the -- adjusting the R/C ratios only apply to existing customer classes? Is there -- is that the evidence, that it wouldn't be to, as you identify it, new tariffs? I mean, sorry; I'm going to back up. One moment. You've stated that -- you refer to R/C ratios being employed to mitigate cost shifting among existing customer classes when rate changes produce

detrimental impacts to a specific customer class. So that's what you have in the evidence. And I'm asking about where is the evidence that R/C ratio adjustments only apply to existing customer classes?

A. (Fitzhenry) That's primarily based on my understanding of how cost-of-service models are dealt with in the various jurisdictions in which I've worked. So again, you know, the principle of gradualism, which says that, you know, a specific rate class that might have a more detrimental financial impact as a result of, you know, cost shifting among changes in cost-of-service studies, that simply, you know, cannot be the case for a class that wasn't involved in the previous, you know, rate case or cost-of-service modelling.

Q. So then just going on from that, from what you said earlier about the new tariffs, so does that mean a new tariff means that they are a new customer class, that they wouldn't be going into an existing customer class?

A. (Fitzhenry) Well, there is an ELID class in this cost-of-service model, I believe. Or excuse me; no, it was not included. Can you restate the question? Excuse me.

Q. Yeah, so I guess I'm wondering whether it would be -- does being under a new tariff mean that they are a new customer class?

A. (Fitzhenry) Yes. When -- not all the time. There's some instances when a new tariff is developed and, you know, or a single customer class will have introduction of a new tariff. So, you know, it's -- an example might be where the cost allocation for a domestic class is -- remains the same, but a new tariff is introduced, for, like, example, a domestic time of use tariff that wasn't previously used. In that instance, the cost allocation, assuming a new cost-of-service model was not developed, would remain the same for the domestic class, but they would have a rate design specifically to serve the domestic time of use class and the domestic

class to ensure that the full cost recovery of the cost of service for that class as a whole would be accomplished through that rate design.

A. (Gorman) Yeah, in this instance, PHP will be the only customer taking service on this tariff rate. At least at this point in time.

Q. Thank you. I just have one last question, if I may. And it just refers to -- we're still in Exhibit N-2. We're going to PDF page 10 of 34, which is document page 8, if you're flipping over in a paper copy.

At line 16 to 19, and this is where you're explaining what you disagree with, and you've mentioned here, it says:

> NS Power's proposal under the ELID Tariff is imbalanced and also ignores the fact that PHP incurs production delays and likely [increasing] operating cost in order to provide NS Power the right to dispatch PHP's load and to interrupt PHP down to the firm demand level with only 10 minutes' notice.

So you refer here in your evidence

that PHP would likely incur operating costs. Has there been any analysis done of those proposed increased costs, what those costs would look like?

A. (Fitzhenry) I don't know. That question would be better asked for the PHP panel.

Q. Thank you.

MS. POWELL: Those are my questions, Mr. Chair.

THE CHAIR: Thank you.

Industrial Group?

(SHORT PAUSE)

THE CHAIR: I'll just throw it out there at the start. Somewhere between 3:15 and 3:30 for the afternoon break, if that works out for you.

MS. RUBIN: Thank you. I'll pay attention.

CROSS-EXAMINATION BY MS. RUBIN

Q. I just want to follow up with a couple of questions from my friends. First there was a question by the Consumer Advocate regarding the range of peak demand of Port Hawkesbury Paper, the coincident demand being -- sorry; the range of peak demand of PHP being 8 to 160 megawatts. Do you recall that discussion?

A. (Fitzhenry) I do recall.

MS. RUBIN: Okay. And if we could turn to Exhibit N-1, page 5 of 19? Okay. And then at lines 24 to 26.

BY MS. RUBIN:

Q. That's the part that was read into the record that speaks about how PHP's:

> ...coincident demand could swing based on the Company's dispatch between very low demand (e.g. 8 [megawatts]) and very high demand (e.g. 160 [megawatts]), depending largely on system load conditions and the level of PHP demand...

You see that?

A. (Fitzhenry) I do see that.

Q. Okay. Now, I want to -- and is your understanding is that that 160 is the highest demand?

A. (Fitzhenry) I'm not aware of where the 160 coincident demand value is coming from. This is the Application I'm looking at? Okay.

A. (Gorman) I mean, I think they qualify this as a "could swing". I don't know if they're necessarily suggesting it's ever been that high in a coincident demand period.

A. (Fitzhenry) Yeah.

Q. Did you review ---

A. (Gorman) But that probably outlines PHP's demand.

Q. Okay. And in preparing your evidence and expressing your opinions, did you review what PHP's actual coincident demand was and how it swung?

A. (Fitzhenry) I absolutely did. On page 15 of my direct evidence, I provide a table, Table 2. It provides six coincident demands that have occurred

between ’22 and 2023. You can see that those coincident demands swing between 9.2 megawatts and 111.2 megawatts; albeit those are inclusive of biomass plant load.

In addition, I have reviewed the additional -- the IRs, which also provide the ‘24 and ‘25 coincident peak demands, where the average was 28 megawatts.

Q. Okay. And your Table 2, you were referring to the data in 2022/2023?

A. (Fitzhenry) That’s correct.

Q. Okay. And here, it’s not limited to any particular year; it just says it could swing between very low at 8 or very high to 160. And my question to you was whether you had reviewed and had a view about whether that was the highest load?

A. (Fitzhenry) Whether -- are you asking whether it was the highest coincident demand or highest load?

Q. Highest coincident demand.

Q. Again, I'll restate my previous response. In my review, I don't recall seeing a coincident demand of 160 megawatts. Not saying that it couldn't have happened. Just I did not see that in my review of historical coincident demands. Albeit I think that was more -- I reviewed more recent years.

Q. Okay. And I just want to clarify something here, then. If I could get you to refer to Exhibit N-10, which is NSPI's response to Synapse IR-23? And this is in the confidential version, but we've already cleared with NSPI and PHP that this could be addressed openly.

THE CHAIR: That was the table; right?

MS. RUBIN: It's PDF page 58.

THE CHAIR: Just open that up first before you move it over, Rob.

MS. RUBIN: Oh, just hold on for a moment. Just bring up the non-confidential version, and I'll read in the number that is blacked out.

THE CHAIR: Okay. That's helpful. Thank you.

Do you have the PDF page for the non-confidential version?

MS. RUBIN: Fifty-eight (58).

THE CHAIR: Okay. Thank you.

(SHORT PAUSE)

MS. RUBIN: It's Exhibit N-10, NSPI's response to Synapse, IR-23, PDF page 58.

MR. NORWOOD: My computer is currently crashing.

MS. RUBIN: Oh, okay. No pressure.

MR. NORWOOD: N-10. Okay. Page?

MS. RUBIN: PDF page 58, I hope.

BY MS. RUBIN:

Q. Okay. And I'll start here just so we can read the question. (c), it says:

> Please provide the total capacity of each tier (1 through 4) of the order of interruptibility during the winter peak. Please also provide the capacity by customer

for each tier of the order of interruptibility, during the winter peak.

And then the answer, if you can scroll down, it's on page 61. Okay. And this is the number that's blacked out. For Tier 2, it says "ELID Tariff", but it's Port Hawkesbury Paper. And the number there is 180 megawatts.

How does that 180 megawatts relate to the range of 8 to 160 megawatts?

A. (Fitzhenry) I'm sorry, you're going to have to scroll back up and let me read the question and then -- I'm seeing -- I do see that ELID peak load reduction 160.

Q. Yeah.

A. (Fitzhenry) And this was an NSP response, correct, to a...

Q. (c). This is NSPI's response to Synapse.

A. (Fitzhenry) Okay.

Q. And it's 23(c). The context is

the order of interruptibility, and it asks for the capacity by customer for each tier of the order of interruptibility during the winter peak.

A. (Fitzhenry) Okay.

Q. And you understand, under the interruption protocols, GRLF is listed first, then PHP, and then the Large Industrial Interruptible customers with the -- sorry; then shore power, then the Large Industrial Interruptible customers. And so this question asks for the capacity by customer for each tier.

MS. RUBIN: And then if you can scroll down to the answer, which is on PDF page 61?

BY MS. RUBIN:

Q. And it lists the quantities; (c):

> The winter peak load reduction for each tier of interruptible customer and each customer in that tier is as follows. Note that the [megawatt] values are peak quantities and may not be reflective of the actual load relief obtained at time of interruption.

A. (Fitzhenry) Okay.

Q. It lists Tier 2, Port Hawkesbury Paper, and the blacked-out number, but which I'm permitted to say, is 180 megawatts. So can you tell me how that 180 megawatts relates to the range of peak demand of PHP being 8 to 160? Should it be 8 to 180?

A. (Gorman) I don't know if we can answer that question without having the load profile information, because the 8 to 160 was coincident peak contribution. These are peak period demands, which may or may not be consistent with the peak coincident, three coincident peak hour demands on the system. So it's -- we just don't have the information to give you a precise answer to that question.

Q. Okay. So if this is the Port Hawkesbury Paper's peak load megawatts, could this be the peak load at coincident?

A. (Gorman) I don't know.

A. (Fitzhenry) This just says "ELID Peak Load Reduction." So this is the -- this is what

their -- I guess NSP has assigned to the number of megawatts that could be interrupted. To say that this number has any relation to, you know, the 3CP demands, I think they're, you know, evaluating two different things.

A. (Gorman) Yeah, I mean, the bottom line is without more information, we can't give you a precise answer. We can't say no, but we can't describe whether or not it does represent PHP's contribution to the three coincident peaks.

Q. Okay. I think I'll leave that for now and just follow up on a question from the Small Business Advocate.

MS. RUBIN: If we could please pull up Exhibit N-2, which is your evidence, Mr. Fitzhenry, PDF page 5, lines 6 through 8?

BY MS. RUBIN:

Q. The statement was:

> If the Board prefers NS Power's proposed design of the ELID, albeit not being cost based, it should be adjusted to reflect NS Power's cost of serving PHP.

And the question was asked about what part is not cost based, and you referred to the interruptible rider using the large industrial costing billing determinants. Is there anything else that's not cost based?

A. (Gorman) Well, I think that generally reflects what we were thinking at the time we developed this testimony, but there's also a potential for further investigation into avoidance of increasing transmission capacity as a credit is related only to the avoidance of production cost.

A. (Fitzhenry) I think I also mentioned previously that the ---

Q. Sorry; can I just follow up on that answer?

A. (Fitzhenry) Sure. Please.

Q. Mr. Gorman, you're talking about the valuation of the interruptible credit, in terms of whether it captures avoided transmission capacity?

A. (Gorman) Whether it captures the avoided benefits to the system. Right now, it's only based on production credits, but to the extent the ability to curtail load also produces the ability to avoid transmission investments, then there could be additional benefits to the system which are captured in the credit.

Q. Sorry; and this is with the interruptible credit?

A. (Gorman) Yes.

Q. Okay. And so I asked is there anything else other than the interruptible credit ---

A. (Fitzhenry) Right.

Q. --- that's not cost based?

A. (Fitzhenry) And the follow up here, that, you know, I think, again, the -- being evaluated at 65 megawatt, you know, 3CP essentially charges us for the 57 megawatts of interruptible demand for transmission service because we're not being currently compensated for the -- we're only being compensated for

the capacity value of that interruptible credit.

In addition, I mentioned previously too that the -- you know, which is new, a new proposal, but at least from what I heard from the testimony from the company was that the priority interruptibility they're proposing to maintain at, you know, $500,000, approximately, as opposed to providing the full 10 percent. So I would say it's primarily what Mr. Gorman said, and those things as well.

Q. Okay. And at the time you drafted your evidence here, when you were speaking about it not being cost based, you hadn't heard that the company proposed to cap the premium at 500,000?

A. (Fitzhenry) I was aware of the company's proposal at $500,000; I wasn't aware that that was a cap.

Q. Right. So when did you reach this conclusion that the proposed design of the ELID was not cost based?

A. (Fitzhenry) I think largely in our evaluation of the evidence in this proceeding, you know, after reviewing the company's Application, we developed our proposals and proposed, again, you know, an alternate rate that is cost based.

Q. Okay. Now, this rate has been under negotiation between NSPI and Port Hawkesbury Paper since about 2023, we heard.

A. (Fitzhenry) This rate?

Q. A form of an above-the-line tariff.

A. (Fitzhenry) Subject to check, I would agree with that timeline.

Q. Okay. And when were you retained by PHP in relation to development of a new above-the-line tariff?

A. (Fitzhenry) Sometime following, I guess, the company's Application in this proceeding. I don't know -- I don't recall the exact date.

Q. Sorry; I thought you were engaged during the GRA settlement negotiations?

A. (Fitzhenry) Yes, I absolutely was engaged in the GRA settlement negotiations.

Q. Okay.

A. (Fitzhenry) Your question was related to when I was engaged for the -- to represent PHP in the -- in this proceeding?

Q. No, no, that wasn't my question. My question was, when were you retained by PHP in relation to development of a new tariff, which -- the elements of which were reflected in the Settlement Agreement and costed out with billing determinants.

A. (Fitzhenry) Sorry, you're right. I misstated your question. I was originally retained by PHP to represent them in the cost-of-service settlement process. I was not retained by them originally to produce an ATL rate on their behalf. That was more recently. I was -- the first time I was retained by PHP to assist them

in the cost-of-service settlement process was maybe early 2024. I'm kind of guessing; I don't recall the exact date, I guess.

Q. Okay. And you were fully engaged at the time of the negotiation of the Settlement Agreement through 2025?

A. (Fitzhenry) Yes, I was.

Q. And we've heard that you had input in the costing determinants?

A. (Fitzhenry) I assisted the counsel with the Settlement Agreement.

Q. Did you have input into the costing determinants?

A. (Fitzhenry) Yes, costing determinants were discussed throughout the Settlement Agreement process.

Q. Okay. And the evidence in the record is that the cost-of-service modelling originated in a demand request or data request from PHP. Do you recall

that evidence?

A. (Fitzhenry) Could you restate that question?

MS. RUBIN: Perhaps we could pull up the exhibit; I believe it's 46.

BY MS. RUBIN:

Q. Mr. Gorman, were you also engaged during this process, as Mr. Fitzhenry was?

A. (Gorman) I was not engaged in the settlement phase of this case. There was another BAI consultant that was -- assisted PHP, along with Mr. Fitzhenry at that time.

Q. Okay. And who was that?

A. (Gorman) Ali Al-Jabir.

Q. Thank you.

MS. RUBIN: Okay. Perhaps you could just scroll down a little bit so we could see at the top, where it originated from? Keep going. There we go. Okay. You can see -- oops. Maybe if you just reduce the

font? That's good.

BY MS. RUBIN:

Q. Okay. At the top, it says, "PHP 4-01," so consistent with the nomenclature. These DRs were assigned a predicate with the originator of the DR, and then by different rounds and series, they're numbered in sequence. You would be familiar with these; correct?

A. (Fitzhenry) Yes, I would be.

Q. Okay. And you reviewed them at the time?

A. (Fitzhenry) I imagine so, yes.

Q. Yeah, you did ---

A. (Fitzhenry) I most certainly did, yeah.

Q. You certainly did. Okay. And so the request is to:

> ...provide a [cost-of-service] study with PHP as an above-the-line customer with the following billing determinants:

And then you see them listed, numbers

one through four. And these are the billing determinants that found its way in the Cost-of-Service Study that underlay the GRA; correct?

A. (Fitzhenry) I'd say there's some similarities. I mean, number two here states:

> PHP's interruptible load will be modelled at actual PHP metered load at the time of NS Power's...(65 [megawatts] for this model).

I believe that the interruptible load in this NSP Application was 57 megawatts. And of course, I think the usage has changed since then.

Q. The interrupt ---

A. (Fitzhenry) But there's -- I would say there's some similarities. For example, "PHP's firm load will be modelled at 8 [megawatts] at the 3 coincident peaks" is certainly included in the Settlement Agreement. And I believe that's also specified in NSP's Application as well.

Q. Right. Any interruptible load is the 57, which is 65 net of the 8?

A. (Fitzhenry) That's correct.

Q. Okay. And where did those numbers come from?

A. (Fitzhenry) I believe at this stage in the process we were, you know, working through various billing determinants on behalf of PHP, trying to arrive at what we think would be, you know, a cost-based rate. So this was part of that investigation.

Q. Okay. And at the time when this request was made and Port Hawkesbury Paper signed off with your advice on the Settlement Agreement, you were satisfied with these costing assumptions as reflected in the Settlement Agreement?

A. (Fitzhenry) I would say largely no. I would say that we included a provision in the Settlement Agreement that allowed for the ELID Tariff billing determinants to be renegotiated at a later time, as part of that Settlement Agreement, in part because we understood that we had to have some billing determinants

in the model or in the settlement, but we also understood that we might, depending on, you know, a number of factors, need to reserve the right to reinvestigate those particular billing determinants at a later time.

Q. Okay. Did you communicate to other participants in those settlement negotiations that you were dissatisfied with these costing assumptions and that ---

MR. MacDOUGALL: Mr. Chair, I don't think we can get into the settlement negotiations, which are confidential, and then we would open up all of the discussions in the settlement. I think we have to be very, very cautious here as to what people say. We have a Settlement Agreement; it has words on it. We will certainly be arguing at the end of the day what those words mean and what **Sattva** and other cases mean around the interpretation and what you can use for the interpretation of a contract, which the Settlement Agreement is. To start with a bunch of questions as to what was said to

participants in a Settlement Agreement that was without prejudice and confidential, I think is a very slippery slope and it could open up the requirement for us to re-cross-examine Nova Scotia Power and potentially other parties.

THE CHAIR: Ms. Rubin?

MS. RUBIN: My discomfort is that the Application is predicated and premised on a Settlement Agreement. The terms of the Settlement Agreement provide that:

> [NSPI] and PHP shall reflect the foregoing in a written tariff which shall also include a proposal...

And the terms are originated with PHP, and now we learned that at the time that this was drafted, the foundation of this settlement is undermined because at no time was there an expectation that this would be pursued. So this evidence that there was no intention to "shall reflect the foregoing" and PHP committed to taking service under such a tariff, is new information to me. So

I think it undermines the very essence of the Settlement Agreement. We can argue about what it means and what position the parties take, but I just want to know when that determination was made and whether it had been communicated to the other parties.

MR. MacDOUGALL: Mr. Chair, if I may?

THE CHAIR: Yes.

MR. MacDOUGALL: The Settlement Agreement has terms in it. Ms. Rubin just indicated her position on it. That's not the position, necessarily, of all parties and not the position of Port Hawkesbury Paper. Port Hawkesbury Paper's position will be, as was communicated just momentarily in response to other questions by Mr. Fitzhenry, that there had to be modelling determinants used in order to model something as a starting point, and then specifically a clause was put in the agreement that says, "All parties have the right to reopen these matters," followed by a clause that specifically created a deferral account to adjust the

matters, which the Board has already adjudicated on. That Settlement Agreement and the legality of that Settlement Agreement will certainly be discussed, I assume, in argument, which we will do, but if we're going to start to try to get parol evidence and talk about what parties said or didn't say, or what parties may have thought it meant, the law in Nova Scotia is not what parties thought a contract they entered into meant. It is to subjectively look at -- objectively look at the language and the totality of the contract that's laid out in **Sattva**. That's what we will be arguing.

Certainly we can't now start getting into he said/she said/who said what. Or we can get into that, but I would suggest that it's inappropriate. And secondly, I would suggest when the law is put in front of the Board, it will understand that that's not what's to be taken into consideration when considering the outcome of a contractual arrangement between sophisticated parties with counsel.

(SHORT PAUSE)

THE CHAIR: Mr. MacDougall, just in terms of the -- your characterization of the law in this point in Nova Scotia, are you suggesting that if the interpretation of a Settlement Agreement is called into question, is in play before a decision-maker, that they cannot hear parol evidence?

MR. MacDOUGALL: No, I'm not suggesting you cannot hear parol evidence, but, you know, the parol evidence rule, I think, will kick in in this case for sure. But if one is going to enter into those discussions on a Settlement Agreement to attempt to get parol evidence, then you're entering into the quagmire of what was said by various parties at various times in the settlement, and I think we would have to certainly re-open our cross-examination to be able to ask that series of questions, and I don't think it's going to be beneficial to the Board. It certainly will put a very serious impediment on the potential to have confidential and

without prejudice settlement discussions in the future.

THE CHAIR: Yeah. I am concerned about that last point, Ms. Rubin. I mean, I think you're entitled to some latitude, given the dispute over the terms of the agreement. I am a little bit concerned about getting into discussions relating to settlements. So there's a very fine line there, potentially.

MS. RUBIN: I appreciate that, Mr. Chair. Perhaps we'll just leave it with one question.

BY MS. RUBIN:

Q. And my question is, can you confirm that that disagreement with the costing determinants was not communicated to the signatories -- other signatories to that Settlement Agreement at the time?

A. (Fitzhenry) I would first state that my concerns about costing determinants were -- I would say it that way, concerns, not necessarily disagreements, were only expressed to my client at that

time.

Q. And so far as you're aware, not communicated to the other signatories to the Settlement Agreement?

MR. MacDOUGALL: Mr. Chair, I don't think now Mr. Fitzhenry can comment on whether comments ---

MS. RUBIN: It was ---

MR. MacDOUGALL: --- were made by counsel in the discussions.

MS. RUBIN: So it was limited to so far as he was aware. And if he is not aware, then he -- that's the extent of what he can say.

MR. MacDOUGALL: Well, maybe you can ask if he's aware at all, one way or the other?

MR. FITZHENRY: So the question -- can I just restate the question? I want to make sure I'm getting this right and I'm not expounding on it too far. The question is, am I aware that PHP, as a party,

expressed concerns about these billing determinants to other parties? That's a yes or no question?

THE CHAIR: I think whether or not -- whether or not they expressed a concern.

MR. FITZHENRY: I am aware that they did.

MS. RUBIN: Mr. Chair, I think we may need to introduce some parol evidence to that effect.

MR. MacDOUGALL: Is Ms. Rubin suggesting there's going to be new evidence found? Mr. Bowman may be up, so...

THE CHAIR: I'm not sure.

MR. MacDOUGALL: Neither am I.

MS. RUBIN: Mr. Bowman will be able to address the information that was communicated of which he was aware, as he also participated in those discussions.

Can I ask a follow up? Whether he's aware that this was communicated in writing?

THE CHAIR: Objection?

MR. MacDOUGALL: Yes, objection.

THE CHAIR: I'm going to allow it.

Go ahead.

BY MS. RUBIN:

Q. Was this disagreement with the costing determinants, or dissatisfaction, communicated in writing to other signatories to the Settlement Agreement?

A. (Fitzhenry) I'm thinking of one specific incident. And I'm just not sure whether I'm allowed to discuss it or not. And to be quite honest, I would like to let either the Board know what the incident is, or the -- or my counsel, to make sure it's okay that I'm allowed to say this. I mean, you know, I'm under oath. You know, we're here, so I'm going to be -- I am aware of an incident where concerns were expressed, which is why I answered affirmatively to your previous question.

THE CHAIR: And I think the question was just the form of that. If you're aware ---

MR. FITZHENRY: Okay.

THE CHAIR: --- of any communication in writing?

MR. FITZHENRY: Okay. Not that I recall.

MS. RUBIN: Okay. I think I'll move on.

Perhaps we could pull up your reply evidence, Exhibit N-36? And turn to page 3. Sorry; the next page. Not PDF page 3, it's page 3 of the document. There you go.

BY MS. RUBIN:

Q. So the question asks:

> Would it be acceptable for PHP to continue to take service under the Extra Large Industrial Active Demand Control ('ELIADC') tariff past its current expiration date?

And the answer says:

> No. PHP's current Tariff, the ELIADC Tariff, which will expire at the end of 2026, utilizes marginal energy cost rates. Marginal cost rates are generally applied to customers that are new to [the] system, charging them a premium energy rate to reflect the incremental cost of power

> required to serve that customer load, or as part of tariffs specifically designed for unique customer situations, such as load retention.

And then you go on to say that, at lines 11/12:

> ...the Company should be permitted to transition to a properly structured ELID Tariff on an ATL basis.

So is your point here that marginal costs are generally reserved for two categories of customers, those new to the system and those in a unique situation such as load retention?

A. (Gorman) I missed the last part of that question. Can you repeat it, please?

Q. Sure. It says -- is your position, as expressed in this paragraph, lines 4 to 8, that marginal cost rates are generally reserved for two categories of customers, those new to the system and those in a unique situation such as load retention?

A. (Fitzhenry) That's correct.

Q. And what do you consider new to

the system?

A. (Fitzhenry) I'm generally thinking about a customer who hasn't been served previously by the -- you know, the utility. So a customer who is, you know, building new facilities and, you know, in particular, that, you know, those new facilities are going to require, you know, investment on behalf of the utility in order to serve that customer. That would be the more common instance where marginal cost rates are applied to new customers.

Q. Okay. And so how long should this customer be permitted to stay on a marginal energy cost rate?

A. (Fitzhenry) I think it's more situation dependent and some jurisdictions will see incremental cost rates be applied for, you know, five years, to I've seen, you know, 15-year contracts as well. So just -- it kind of depends on the situation and certainly the jurisdiction that's involved in those, you

know, discussions.

Q. And would you acknowledge that Nova Scotia Power has marginal cost rates below-the-line that have been in existence for decades?

A. (Fitzhenry) Yes, that's my understanding.

Q. Okay. And that would include the real-time pricing tariffs?

A. (Fitzhenry) I'm not intimately familiar with, you know, a lot of the rates, you know, well before the ELIADC tariff.

Q. It's not just before the ELIADC tariffs. There's a current real-time pricing tariff.

A. (Fitzhenry) Sure. The marginal cost is based on, you know, real-time pricing. So yes, that would include that tariff as well.

Q. Sure. And that's not restricted to customers new to the system?

A. (Fitzhenry) Not currently.

Q. Not ever?

A. (Fitzhenry) I don't know that.

Q. Oh, okay. And what about -- that tariff is also not a Load Retention Tariff?

A. (Fitzhenry) It is not.

Q. Okay. And the Shore Power Tariff; are you familiar with that?

A. (Fitzhenry) I'm not very familiar with that tariff.

Q. No, okay. That's tied to NSPI's forecast average annual marginal energy cost, or you can't say one way or another?

A. (Fitzhenry) Subject to check, I'll agree with that.

Q. Okay. And I take it you don't know whether that's restricted to customers new to the system?

A. (Fitzhenry) That particular tariff, I don't know.

Q. It's not a Load Retention Tariff?

A. (Fitzhenry) Not to my knowledge. Again, I'm not intimately familiar with the tariff, so...

Q. And Nova Scotia Power maintains a Generation Replacement Load-Following Tariff?

A. (Fitzhenry) I'm not sure if I'm familiar with that tariff either.

Q. Okay. So you wouldn't be able to say whether that uses marginal costs as well?

A. (Fitzhenry) I would not. My statements here are based on my previous experience in dealing with other jurisdictions primarily outside Nova Scotia.

Q. I see. So this paragraph 4 to 8 doesn't have any applicability, necessarily, in Nova Scotia?

A. (Fitzhenry) I wouldn't say that. I characterized, you know, the -- how marginal cost rates work and why that would be inappropriate for an embedded

cost-of-service customer, or excuse me, a customer who has contributed to the embedded cost-of-service for decades.

Q. Are you familiar with the Extra-Large Industrial Interruptible rate, the ELIIR?

A. (Fitzhenry) I am.

Q. Okay. That was the rate that the mill took power and it was a below-the-line rate approved in 2004?

A. (Fitzhenry) I'm sorry, I misspoke. I thought you said the LIIR, not the ELIIR. I'm familiar with the LIIR.

Q. It's extra-large.

A. (Fitzhenry) Sorry; I misheard that. I'm not familiar with that.

Q. Okay. This was the rate that applied to the mill to the predecessor owner, Stora Enso. Not familiar with it?

A. (Fitzhenry) No.

Q. Okay. And that also used

marginal costs and introduced the concept of economic interruptibility. You don't know that?

A. (Fitzhenry) No, I'm not familiar with that rate.

Q. Okay. That wasn't a Load Retention Tariff either; you can't say one way or another?

A. (Fitzhenry) I'm not familiar with that rate.

Q. Would you acknowledge that there are numerous tariffs in addition to the ELIADC that use marginal cost pricing on a longstanding basis in Nova Scotia without being limited to new customers or load retention situations?

A. (Fitzhenry) I'm aware that PHP has been on a marginal cost rate for a long period of time.

Q. And so that, in and of itself, isn't the basis to say they should be permitted to transition?

A. (Fitzhenry) I would disagree. Again, I think PHP, who has contributed to embedded cost of service for decades, should be permitted an opportunity to transition to an ATL cost-based rate.

Q. Is there anything that says they're not permitted?

A. (Fitzhenry) I don't believe so.

Q. Okay.

MS. RUBIN: I'm reminded of the time. This would be a good time to take a break.

THE CHAIR: Thank you very much, Ms. Rubin.

So it's 25 after 3:00. We'll come back at 20 to 4:00.

--- Upon recessing at 3:25 p.m.

--- Upon resuming

MICHAEL GORMAN, Resumed:

COLIN FITZHENRY, Resumed:

THE CHAIR: Okay. Whenever you're

ready, I think, Ms. Rubin.

MS. RUBIN: Okay. I think we'll stick with the reply evidence, which is Exhibit N-36. And if we can turn to PDF page 8, which is page 7. Right, okay.

CROSS-EXAMINATION BY MS. RUBIN, (Cont'd)

Q. And the first section addresses Mr. Bowman's proposal to use PHP average demand in developing a demand allocator. And your reply evidence characterizes his proposal to use the PHP average demand, rather than its three coincident peak contribution, as discriminatory towards PHP; correct?

A. (Fitzhenry) That's correct.

Q. Okay. And you've contrasted your understanding of his recommended approach with the fact that the three coincident peak demand allocation is the standard approach used for all other above-the-line customers; correct?

A. (Fitzhenry) That's correct.

Q. Okay. And you characterize this

at line 7 to 8 as an admission by Mr. Bowman?

A. (Fitzhenry) That's correct. Mr. Bowman admits that the 3CP demand allocation is the standard approach used for all other ATL customer classes.

Q. Right. He admits that, you said?

A. (Fitzhenry) That's correct.

Q. And did you review Mr. Bowman's Opening Statement before today?

A. (Fitzhenry) I believe I have.

MS. RUBIN: Perhaps we could pull that up. It's Exhibit N-44, and page 4 of that.

BY MS. RUBIN:

Q. Okay. And if you look at the third full paragraph, where it begins, "Brubaker's rebuttal...", Mr. Bowman states:

> Brubaker's rebuttal...indicates I have proposed discriminatory rate making by suggesting PHP peak load for [cost-of-service] purposes use average demand while other classes use anticipated 3 CP demand. This is not correct. I propose that PHP use the expected 3 CP peak demand, based on a high load factor load prior to DR, which

PHP's own witnesses confirm should be assumed if there were no DR. My concern is that the NSP proposal is discriminatory towards PHP by double-crediting dispatchability.

So he states in his Opening Statement that your characterization of his evidence is not correct. Do you see that?

A. (Fitzhenry) I do see that.

Q. Okay. And he has explained what his proposal is?

A. (Fitzhenry) Yes, to use the average demand based on -- to use the 3CP of the average demand, I believe is what he's suggesting here.

Q. He proposes that PHP -- I'm going to use his words here so that there's no misunderstanding; he proposes that PHP use the expected 3CP peak demand based on a high load factor prior to DR. Do you understand that?

A. (Fitzhenry) I do see that.

Q. Okay. So by his description, his

proposal uses the same coincident peak methodology applied to other above-the-line classes, and the only difference is the load level that methodology is applied to; correct?

A. (Fitzhenry) Well, I would say it's not the same methodology because other classes' 3CP demand are based on historical or forecasted demand levels. There's no -- Mr. Bowman isn't suggesting that PHP will be at a high load factor during periods of coincident peak.

Q. He's proposing that the -- use the expected 3CP based on a high load factor prior to DR because the DR is being credited separately.

A. (Fitzhenry) I understand his proposal. Yes, that's correct.

Q. Okay.

A. (Gorman) But to add in to that, it does not reflect the actual load characteristics of PHP, and that's why it's inappropriate.

A. (Fitzhenry) Right. It's

discriminatory because it's not -- it's very, very unlikely that PHP will be at 120 megawatts during periods of 3CP. They've never -- they've rarely been close to that value on a historical basis, and on a forecasted basis it's very, very unlikely that they will be at that level.

Q. Because they've been dispatched down?

A. (Fitzhenry) I would say for a number of reasons. I mean, they potentially could have been dispatched down. I mean, the historical 3CPs kind of speak for themselves. That's where they've been during periods. I believe PHP's testimony has some specific evidence about the operating conditions of PHP at those historical 3CPs.

Q. But you ---

A. (Gorman) And also, it's intended to represent the resource cost that Nova Scotia Power has incurred in order to serve their system's peak demand, and

accurately measuring customer's contribution to that coincident demand is a means of allocating Nova Scotia's cost and providing service to that customer.

Q. Mr. Fitzhenry, in using the 3CP of the -- of other classes, it's reflective of their own operational decisions; correct?

A. (Fitzhenry) Could you restate that question? I wasn't quite following it.

Q. In using the 3CP, the standard methodology, for other above-the-line classes, it's reflective of their own operational decisions? NSPI isn't directing them?

A. (Fitzhenry) That's correct, NSPI isn't directing the domestic class when their 3CPs are being set.

Q. Or the large industrial ---

A. (Gorman) Those 3CPs, in turn then, are factors that Nova Scotia must design its system to be able to serve.

Q. Okay. So for the large industrials; correct?

A. (Fitzhenry) Sorry, what was the question?

Q. The question was the coincident peak of the class ---

A. (Fitzhenry) Yes?

Q. --- occurs undirected by NSPI? It reflects a collection of individual customers' own operational decisions, if they're corporate entities, businesses, or just the -- if it's a residential class, it's how they run their house. They aren't being directed by NSPI; correct?

A. (Fitzhenry) Yes, I think that's largely correct. To the extent, you know, a large industrial customer has ability to control its operational decisions at times of coincident peak, it could potentially make adjustments. More likely, a domestic class customer would not be able to, you know, direct its

demand at the time of 3CPs. You know, mostly because, you know, neither PHP, nor any of these customer classes, likely know when a 3CP will occur.

Q. Sure. And industrial customers will do their best to operate at a high-load factor and avoid peaking at times of system constraints in the winter peak, so they avoid that ratchet?

A. (Fitzhenry) I'd imagine they would be incentivized to operate in that manner.

Q. Of course, because if not, then if they have a single spike, maybe because a piece of machinery has to start up suddenly after a shutdown, that could carry through the rest of the year?

A. (Fitzhenry) Certainly any sort of, you know, increases in peak demand during -- that align with a 3CP would result in more cost allocation for the class, not just the individual customer.

Q. For the individual customer, though, from a billing perspective, ---

A. (Fitzhenry) Oh, excuse me. You're right. From -- because of the ratchet. It was based on their individual billing demands; correct?

Q. Right.

A. (Fitzhenry) Okay.

Q. And under this proposal, because it's fixed, then that same operational motivation doesn't apply to PHP, their motivation is a financial one to shape their load and response to a dispatch request to save.

A. (Fitzhenry) You're saying because the fixed demand charge -- the demand charge is fixed, PHP is not incentivized to adjust its demand during times of 3CP?

Q. I'm saying they have different incentives. They don't have a different -- their billing demand isn't ratcheted, it's fixed.

A. (Fitzhenry) That is correct. That's NSP's proposal, that's correct.

Q. Correct. And you haven't taken

issue with that?

A. (Fitzhenry) No, I have not. No, I think PHP will be incentivized to operate in an efficient manner for numerous reasons. Of course, you know, the dispatchable rider, which will provide fuel and, you know, O&M cost savings, but in addition, you know, PHP is going to know going forward that it's going to be subject to, you know, these types of review processes where their historical demands are going to be evaluated for their peak demand contribution and, you know, they're going to be -- certainly be cognizant of that too when operating on a going-forward basis.

Q. Right. But my point was, so in setting the 3CP, one can't look at PHP in the same way one looks at the other customer classes whose coincident peaks occur irrespective of the directions of NSPI?

A. (Fitzhenry) I would disagree with that. I think, you know, based on cost-causation principles, as my colleague, you know, keeps reiterating

here, you know, the 3CP is used for planning purposes, so it informs both the system need and the planning reserve margin. So, you know, PHP is, while maybe having some -- even though it's primarily being directed by utility how to dispatch, you know, while it has -- it might maintain some more operational control, but it will certainly be incentivized to reduce its demand, I think, during, you know, times of peak demand.

Q. Okay. If you want to treat the 3CP, regardless of its -- that it's directed by NSP, then shouldn't PHP also be subject to a ratcheted demand charge in the same way that any other above-the-line customer would be, like the large industrials?

A. (Fitzhenry) I don't think that would be appropriate for the ELID Tariff, primarily because just of the load flexibility for the particular class. Their load range is between 8 megawatts and, you know, 200 -- well, not quite 200, maybe -- around 200, say, megawatts. So, you know, applying a billing demand

ratchet, you know, is -- it basically incentives the customer not to operate at all during certain months of the year, which wouldn't necessarily be in the best interests of the system. And certainly in periods of the winter, there's excess energy on the system and PHP is in a position to take advantage of that. So I don't think that would necessarily save the system any money and I don't think it would be, you know -- I think it would cause, obviously, you know, cost fluctuations to PHP and revenue recovery issues for the company. So I don't think it would be in the best interest of any party.

A. (Gorman) Yeah, I don't think it's reasonable either and doesn't reflect cost causation. You know, all industrial customers have an incentive to maximize the efficiency of their operations, and that includes controlling, to the greatest extent possible, their cost of inputs, including electric power. You know, PHP and all other industrials do that in a manner that is directed from price signals provided by the utility in

order to accomplish that objective.

So in the end, all customers' contribution, this system coincident peak is the demand component which is evaluated by the utility to determine whether or not it has adequate resource capacity. And it's that resource capacity then should be allocated across the various customer classes in proportion to how they contribute to that system peak.

And in terms of a declining -- or a stepped demand block rate, declining demand block rate, or stepped demand block rate, that would imply there's different levels of cost, depending on the demands they placed on the system. And that doesn't truly reflect the interruptible nature of PHP's load.

Q. What did you mean by "declining demand block rates"?

A. (Gorman) I was trying to reiterate your question. You suggested there would be demand block rates.

Q. No. No, I didn't. I'm not -- I don't even know what a demand block rate is.

A. (Gorman) Well, I was attempting to replicate your question and respond to it. If you repeat your question, I can repeat my response.

Q. I don't think I can repeat my question because I'm not sure what you were responding to, Mr. Gorman, so I think I'll just move on.

Okay. Mr. Fitzhenry -- could I get you to turn to PDF page 6 of your reply evidence, N-36?

MS. RUBIN: And I -- I think it's 6. No, sorry; it's page 4 at the top. Yeah, that's the one. Okay.

BY MS. RUBIN:

Q. At lines -- this section addresses the -- Mr. Bowman's proposal to use the demand of 120 megawatts, and this is the discussion about discriminatory ratemaking principles. And then at lines 12 to 13, you say:

> The IG witness acknowledges that this change dramatically shifts costs, adding an estimated...9.4 million to PHP's annual allocation.

You see that?

A. (Fitzhenry) I do.

Q. Okay.

MS. RUBIN: Now could I get you to turn to Exhibit N-15? And that's PHP's response to NSPI IR-2, Table 1.

BY MS. RUBIN:

Q. And so we've looked at this table a few times, and this discusses the reduction in cost allocation to PHP created by the reduction in PHP demand from 65 megawatts to 8 megawatts, as you've proposed, and it breaks it out by service area. Do you see that?

A. (Fitzhenry) I do.

Q. Okay.

MS. RUBIN: And if you could scroll down to the next page, please? There we go.

BY MS. RUBIN:

Q. That's the total. And the total cost of shifting the demand from 65 megawatts to 8 megawatts, as you've proposed, is 9.42 million in 2027. So I take it you would agree that is a dramatic shift of costs?

A. (Fitzhenry) Yes, I would say it's a significant shift in costs.

Q. A dramatic shift of costs? Those are your words?

A. (Fitzhenry) That's correct, a dramatic shift in costs. I would note that, you know, my position is that as the NSP Application, at the current allocation of cost to PHP is an overallocation. So certainly, you know, any increase would be, in my view, or any large increase would be a dramatic shift.

Q. Okay. This one is going the other way, though. This is shifting costs from PHP to other customers?

A. (Fitzhenry) I understand that

this would be -- result in a negative $9.4 million allocation of cost to PHP.

Q. Right. And cost allocation's a zero-sum game, generally, right?

A. (Fitzhenry) As I stated previously, I don't know how these costs would be covered by NSP, or if at all, but certainly, you know, $9.4 million being shifted is significant. Well, the biggest difference here is that it's an impact to -- a $9.4 million increase to in-class -- to one class. you know, this $9.4 million decrease would be spread, if spread across all classes, wouldn't apply to one particular class.

MS. RUBIN: Now, can we go back please to that last page that we were looking at in the Exhibit N-36? Page 4 at the top, yeah, and lines 13 to 16.

BY MS. RUBIN:

Q. And now that says:

> From strictly a regulatory perspective, constructing an intentionally punitive cost-

allocation mechanism that is explicitly denied to all other customer groups violates the principle of rate uniformity and results in an undue prejudice against a single customer class.

Now, when you said it's "constructing an intentionally punitive cost allocation mechanism," are you suggesting that Mr. Bowman is not adhering to cost-of-service principles and he is intending to punish PHP?

A. (Fitzhenry) I would say that the resulting, you know, allocation or change in allocation is punitive. I'm not suggesting that -- again, I'm not suggesting that Mr. Bowman has any intention to punish or has a desire to punish PHP. I think I'm specifically speaking from a, you know, impact standpoint from PHP's perspective.

A. (Gorman) Yeah, the effect of his proposal is to allocate is to allocate too much production cost to PHP, and that does harm PHP.

Q. I was just looking at the words, "constructing an intentionally punitive proposal," but

you're now saying it's -- you're really speaking of the effect of it?

A. (Fitzhenry) That's correct.

Q. Okay. So you're not ascribing any mal-intent?

A. (Fitzhenry) No, I'm not.

MS. RUBIN: Can I just take a moment?

(SHORT PAUSE)

BY MS. RUBIN:

Q. Thank you, Mr. Fitzhenry and Mr. Gorman.

A. (Fitzhenry) Thank you very much.

THE CHAIR: I think that's everyone, up to Board counsel.

Mr. Mahody?

MR. MAHODY: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MAHODY

Q. And good afternoon, gentlemen.

MR. MAHODY: Mr. Norwood, could we call up Exhibit N-2, PDF page 30? And it's lines -- beginning at line 4, if we could highlight that section?

BY MR. MAHODY:

Q. So here, gentlemen, in your evidence, you've asked yourself the question:

> What do you recommend this Board approve as the appropriate energy requirements for calculating PHP'S new above-the-line tariff in this proceeding?

And your response begins with:

> We would recommend that the proposed ELID tariff reflect the current forecast energy sales as provided in PHP's direct evidence. These forecasted energy sales figures more accurately reflect the likely energy sales to PHP in the applicable years.

What is the basis for your statement that these forecasted energy sales figures more accurately reflect the likely energy sales to PHP?

A. (Fitzhenry) Primarily just

because they're more recent. I think they have more recent evidence to support the figures.

Q. You said "primarily," I think. And what other factors, other than the recent nature of them?

A. (Fitzhenry) I mean, I think that's primarily -- I would have to -- let me look back at my other portions of testimony, but yeah, I think essentially the more recent figures are -- well, with any forecast -- for example, with any forecast, as you get closer for, you know, take example, you know, a natural gas forecast or a power price forecast, as you inherently get closer to the trade date, or the execution date of those four contracts, the difference or the delta between the actual price and the forecasted price is narrowed, and that's because there's more market fundamentals informing that forecast.

So in the same way that a forecast becomes more accurate as you get closer to the trade date,

or the forward month of that contract, you know, a forecast, in terms of whether it's power, you know, a wind output, you know, generation profile, or even a customer's energy usage is informed by more fundamentals and more exact evidence that informs that forecast.

A. (Gorman) And I guess these forecasts itself could be based on multiple factors underlying its expected production in energy consumption from NS Power. So all of that would kind of fall under the umbrella of updated forecast.

Q. And Mr. Gorman, did I hear you say, "could be"?

A. (Gorman) Typically it is based on, yeah, their most recent outlook for production and based on the energy consumption and the other factors that go into driving their energy demands.

Q. And in preparing your testimony for this matter, did you review PHP's current forecast energy sales model?

A. (Gorman) It was based on representations that we understand from PHP and their expected operations over the next few years.

Q. Understood. So no review of the model itself?

A. (Gorman) No, simply ---

Q. No.

A. (Gorman) --- recognizing that they update their forecast and that's, I think, the most -- that's the best estimate of their expected energy consumption at this point in time.

Q. And you heard testimony today, and I believe there's an undertaking in this regard, that a more recent forecast has been provided. I take it your opinion would be the same in relation to the preferred nature of that more recent forecast, even than the one you reviewed as part of the -- PHP's evidence in the matter so far?

A. (Gorman) I would think ---

A. (Fitzhenry) Yes, as I just said, I think generally the accuracy or forecasts improve as it gets closer to the date of the -- start date of that forecast.

A. (Gorman) Yeah, subject to review of PHP, agree.

MR. MAHODY: Next in this same exhibit, could we turn to PDF page 10, please? And it's line 16, if we could.

BY MR. MAHODY:

Q. And here you indicate:

> [Nova Scotia] Power's proposal under the ELID Tariff is imbalanced and also ignores the fact that PHP incurs production delays and likely increased operating cost in order to provide [Nova Scotia] Power the right to dispatch PHP's load...

For your position that PHP incurs production delays, what was your basis for that statement?

A. (Fitzhenry) Well, I think that's largely informed from the evidence provided by PHP. Certainly any sort of reductions in their generation

output -- or excuse me, their load, necessitates, you know, a changing of their operations, which could result in reduced production.

Q. But did you receive any records from PHP that -- demonstrating that PHP has or will incur production delays associated with the tariff?

A. (Gorman) We did review and have conversations with PHP personnel about how they are able to allow NS Power to request dispatch to their service, and the resulting consequences to PHP of complying with those dispatch, and this summarizes, ---

A. (Fitzhenry) Yeah, and I think ---

A. (Gorman) --- my understanding.

A. (Fitzhenry) Yeah, and I think a lot of those conversations with PHP discuss how they were incentivized to operate in a certain manner and whether the level of incentive under the ELID tariff was, you know, elevated enough to continue to -- to continue to use those -- you know, those dispatch tools, or whether it'd

be more efficient just to forgo the savings of them under the proposed ELID Tariff and operate in a different manner.

Q. And Mr. Fitzhenry, can you provide the magnitude and duration of the production delays you referred to here?

A. (Fitzhenry) I don't have a specific -- go ahead, Mike.

A. (Gorman) Yeah, we don't have that detail. It's just based on general conversations with PHP about how they're able to operate under the structure of this tariff rate.

Q. Fair enough. And is it the same regarding the increased operating cost; that that, again, is based on conversations you had with PHP but that you didn't -- weren't involved with reviewing documents in that regard?

A. (Fitzhenry) I think the evidence of increased operating costs is being -- is provided in

this proceeding. I think, you know, if have specifics about how those costs are incurred, I would suggest, you know, asking PHP in their testimony and they could discuss it in greater detail.

Q. So you're aware, on the record of this proceeding, Mr. Fitzhenry, that there's a quantitative calculation of increased operating costs associated with this tariff?

A. (Fitzhenry) That's not what I said, no. I said I believe that the understanding that there's operating costs associated with being interruptible and being dispatched is clear in the evidence provided by PHP. If you have additional questions about the magnitude of that operational cost, they might be able to provide, you know, more details.

Q. Okay. But you don't have any information on that today?

A. (Fitzhenry) I would just reiterate what we've stated previously, that we've had

conversations with PHP, which gives us an understanding of the production delays and impacts of those types of dispatchability and interruptions.

Q. You also refer here at line 18 to Nova Scotia Power's right to dispatch PHP's load. Do you see that?

A. (Fitzhenry) Yes.

Q. Now, as I heard Nova Scotia Power's testimony today, Nova Scotia Power is a bit like a third-base coach regarding this dispatchability. They put up a signal, but PHP can run through it. Familiar?

A. (Fitzhenry) I recall the company's testimony with respect to that manner.

Q. Okay. So is it more accurate to say that Nova Scotia Power doesn't so much have a right to dispatch, they have a right to provide directions regarding dispatch, but it's up to PHP whether or not that direction will be complied with? Is that fair?

A. (Fitzhenry) I think it's a fair

characterization of their dispatchable rider.

Q. And next, could we turn to your reply evidence?

MR. MAHODY: It's Exhibit N-36. And it's PDF 23. Line 4 is where I'm headed here.

BY MR. MAHODY:

Q. And here at this portion of your reply, you indicate:

> Bates White outlines a highly speculative scenario where PHP's annual net load drops to zero, concluding that the mill would completely evade its responsibility for embedded system costs. This claim relies on an incorrect premise that ignores the total billing structure of the ELID Tariff. Even in a hypothetical scenario where the mill's net energy purchases drop to zero due to the wind farm offset, PHP remains fully responsible for paying the fixed customer charge, and a fixed capacity [and] demand charge based on its peak coincident system contribution.

Is it your testimony that in a scenario in which PHP's annual net load drops to zero, PHP will still pay its full share of the fixed costs under the ELID Tariff?

A. (Fitzhenry) Yes, that's my understanding.

Q. Now, you heard Nova Scotia Power's testimony ---

A. (Fitzhenry) Excuse me. Can I just clarify? Fixed customer charge and fixed capacity demand charge, not fixed energy charge. You just -- you said just fixed costs; correct?

Q. Yes, I did.

A. (Fitzhenry) Okay. So I'm just clarifying that it would still pay for the fixed customer charge and fixed capacity demand charge.

Q. Okay. I think what you're indicating to me is the answer to my question is no, that they're not going to pay their full fixed cost under the ELID, because we're -- you're going to exempt out energy, as I understand it? Fix a portion of that?

A. (Fitzhenry) My understanding under the proposed tariff, that if Goose Harbour output is

greater, right, than the PHP energy usage, then that would reduce the customer energy charge to zero.

Q. Okay. And you heard the testimony from Nova Scotia Power today that somewhere in the range of 20 percent of the energy charge is actually fixed cost recovery?

A. (Fitzhenry) Yes, I understand that as well.

Q. And that's not going to be collected in the scenario in which the net flow drops to zero?

A. (Gorman) That's ---

A. (Fitzhenry) The energy component ---

A. (Gorman) --- true, but over the course of a year, the energy charge can be more than what was expected in the rate case, and other times, it's less. So to the extent the energy consumption over the course of a year is in line with what's expected to be sold to PHP,

then they won't recover that fixed cost based on energy charges.

Q. Yes, Mr. Gorman. My premise was that PHP's annual net load drops to zero. And in that scenario, the fixed charges to be recovered under the energy charge would not be recovered?

A. (Gorman) That's true, if it dropped to zero for the calendar year.

A. (Fitzhenry) Yeah. I would say that -- so there's two -- the production capacity cost that you're referring to is allocated to both demand and energy and you're talking primarily about the energy component?

Q. Yeah, I'm sorry, I didn't refer to production capacity costs. I referred to fixed costs, and I was referring to Nova Scotia Power's testimony that the energy charge has -- approximately 20 percent of it is fixed costs. And those are what's forgone in the scenario that Bates White has referred to. But you'd agree with me

on that?

A. (Fitzhenry) Yes, I would.

Q. Okay. All right. Final question is in your Opening Statement.

MR. MAHODY: It's N-42. And it's page 2 of N-42, in paragraph 3. Yes, it's just in that third paragraph. You'll see it begins with "Finally," and it's down near the bottom.

BY MR. MAHODY:

Q. And you say that:

> Similarly, compensating PHP with a 10 [percent] premium for Priority Interruptibility is fully justified because PHP accepts the highest-risk tier of forced curtailment, directly shielding other industrial customers and operating reserves from disruption.

Are you saying there that the cost of that priority interruptibility should be borne by the -- just by the other industrial customers?

A. (Fitzhenry) No, I'm -- I am alluding to some of the benefits provided to the large

industrial class, or Large Industrial Interruptible class as a result of that priority interruptibility, but I would also suggest that there's lots of ancillary benefits provided by PHP's interruptibility, including, you know, operating reserves, including, you know, the priority, so that -- and as I understand from, you know, the company's testimony as well, the dispatchability also provides additional benefit that's not quite quantified, but provides capacity benefits.

So I think for all those reasons, you know, a 10 percent premium on priority interruptibility is appropriate, and I think it benefits the total system, including the Large Industrial Interruptible class.

Q. All right. Thank you.

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

MR. FITZHENRY: Thank you.

QUESTIONS FROM MEMBER MELANSON

Q. I have one question, maybe two.

My first question relates to the updating of forecasts when the GRA takes place and you have your forecast put in place, and your rates are based on the forecast, and the revenue requirement is based on those forecasts that you use for above-the-line rates, is it fair when you are then dealing with above-the-line rates, although it's being initiated, it appeared, at the test years, is it fair to update the forecast to the other rate customer classes?

A. (Fitzhenry) So in the instance, I wouldn't -- the company is performing an update for -- on, you know, to adjust the ELID forecast distribution, would it be appropriate to look at the other class forecast distributions too?

Q. Or if that's not possible, because that's generally not how we do it, why is it appropriate to change the forecast amounts for the ELID

that's an above-the-line rate in-between GRAs?

A. (Fitzhenry) Yeah, I think just because of the dynamic nature of their load, it's particularly important to make sure, you know, that we get it right. Certainly there's been, you know, the dynamic changes in the, you know, the Purchase Power Agreement and the ability to construct those wind turbines, and that information is being updated quite frequently. Certainly, you know, PHP as a class, because it's a single customer, you know, receives updates from its customers and clients too, and that updates its forecasts as well. So I think, you know, for all those reasons, and just because of the revenue impact to PHP, but also NSP, you know, it's important to get it right here, and that's why we're proposing in this instance to re-examine those values and update them if necessary.

Q. And the same question with respect to R/C ratios. The R/C -- I understand that the R/C ratio is a derivation of what the Settlement Agreement

numbers were and you're challenging the -- some of the numbers in the Settlement Agreement, but the R/C ratios were approved in the GRA and they were established. Is it appropriate to change the R/C ratio for one class of customer just because it's a new rate?

A. (Fitzhenry) You know, I'm not an attorney, but my understanding is that the provisions of this Settlement Agreement, you know, explicitly provide, you know, that opportunity to re-examine these billing determinants and the components of the ELID Tariff.

You know, as this Application was filed, I think, you know, as an expert witness, my responsibility is to review that Application and ensure that it's, you know, based on cost-causative principles.

So, you know, I'm looking at that one point, you know, whether it's the 1.4 R/C ratio, or whether it's a different billing, you know, I think, you know, my responsibility is to, you know, provide a recommendation based on my own expert opinion and what

cost causation, you know, is acceptable under -- you know, based on my expert opinion.

Q. Sure. And I understand that part of it, but the general principle, ordinarily when you have above-the-line rates and you establish in the GRA what the R/C ratio is going to be, and you establish in the GRA what the forecast numbers are, individual customers can't come in -- individual rate classes can't come in and adjust that because they think it's unfair a year later. There could be an entire rate case that might decide that, but isn't there something from a general ratemaking perspective that's off about doing that for one customer -- for one class? And I realize in this case one class is one customer, but it's -- you know.

A. (Fitzhenry) Yeah.

A. (Gorman) Well, I think this rate provides some flexibility on that with the deferral account. So since NS Power can be made whole for any small changes that we're proposing here, the deferral

account could pick up those differences in revenue, then the Board can decide how it will go about recovering that deferred cost.

Q. Sure, but you're creating deferral accounts for almost any projection that's made in a rate case, but this is an exceptional situation where there was no rate to consider at the time of the GRA. But would you agree with the proposition that deferral accounts in general, as a ratemaking principle, should be kept as low as possible?

A. (Gorman) Yes.

Q. Okay. Those are my questions.

THE CHAIR: I'm going to start with the Opening Statement that I think is already up there. Mr. Norwood, though, if you could just go to the first page?

QUESTIONS FROM THE CHAIR

Q. Mr. Fitzhenry, I'm just going to start with the second paragraph there, midway through the statement:

> While we support this structural transition in principle, the proposed rate design and cost allocations filed by Nova Scotia Power, as well as the alternative proposals advanced by certain intervenors, depart sharply from fundamental cost-causation and non-discriminatory ratemaking principles, resulting in a substantial over-allocation of costs to PHP.

My question relates to your support of the structural transition in principle. I'm wondering if you could elaborate for me why you support a structural transition and what principles you're sort of basing that on?

A. (Fitzhenry) I think, you know, when you have good cost-of-service allocation and methodologies, most customer class -- most customers can get -- you know, be an embedded cost-of-service customer. And that way, they're subject to cost-causative principles

as opposed to, you know, my discussion here of marginal costs -- marginal energy rates, which I don't believe are, you know, cost causative, especially for a customer like PHP, who is often operating, you know, at times of, you know, very low marginal cost. So -- or in off-peak periods. So again, it's -- I think, you know, customers should have an opportunity to be served under an ATL rate, just like every other customer class that's informed by cost-causative principles. So that's the basis of that recommendation.

Q. Could I summarize that by saying generally you view embedded cost rates as being overall fairer for all ratepayers than marginal cost rates?

A. (Fitzhenry) Yeah, I think so long as the Cost-of-Service Study is -- you know, there's good cost, you know, causative principles engrained in the Cost-of-Service Study, I think that's generally the case, yes.

THE CHAIR: Mr. Norwood, I'd now like

to go to the reply evidence, please. That's Exhibit N-36. Page 6 in the PDF, and I'm focusing on lines 9 to 12.

BY THE CHAIR:

Q. There's a statement made there:

> Forcing PHP [onto] an inflated 120 [megawatt] demand allocation, calculated by assuming a flat, high-load-factor profile, nearly doubles its capacity assignment from the 65 [megawatts] proposed in the application.

I guess my question is really, isn't the assumption -- the foundational assumption for the rate itself, the design of the rate, that absent following dispatch directions, PHP would be operating at a flat, high-load-factor load?

A. (Fitzhenry) The CBL is certainly a flat high-load-factor load, but I think my concern here is that on a forecasted basis, there's no anticipation that they'll be operating at 120 megawatts, which is why I find it to be discriminatory.

A. (Gorman) Not during system peak.

A. (Fitzhenry) Yeah, not during

system peak, correct.

Q. Sure. But the premise is, absent the dispatch rider, I think what we're being asked to accept is, left to their own devices, PHP would be operating at a flat high-load-factor rate. Do you agree with that? Or load. Do you agree with that?

A. (Fitzhenry) I think the -- yes. I think similar, if they weren't incentivized to reduce their energy usage to, you know, to avoid bringing additional -- bringing on additional generation, or avoid high fuel costs, if they were immune to any sort of, you know, price signals to, you know, incentivize, you know, raising or increasing that 120 megawatt level, then generally it would be most operationally efficient, from my understanding, to operate at a flat level.

A. (Gorman) Yeah, but the cost we would be allocating for Nova Scotia Power would be different if -- under that assumption. So what we're trying to do is allocate what Nova Scotia Power's actual

costs are, and that's not to serve 120-megawatt coincident peak contribution from PHP, but something less than that on a combined firm and interruptible basis.

Q. Yeah, my understanding -- so my understanding is that the rates under the proposed design going forward are going to be allocated to other customers based on the assumption of a flat high-load-factor load for PHP. Do you not -- is that unfamiliar to you?

A. (Gorman) Well, the three coincident peak contribution is how the fixed cost would be allocated across the rate classes. And the contribution of coincident peak is what NS Power will design its system to be able to serve. So there is a tie between what NS Power's actual costs are and those costs that we're allocating across the customers' classes based on their contribution, the load characteristic that causes NS Power to incur costs to serve those customers.

Q. Sure, but the costs that are allocated to other customers are going to be premised on

PHP not operating at an optimal load, operating a flat high-level load, is my understanding.

A. (Fitzhenry) That would be under the FAM; correct? Not under the fixed costs and cost-of-service?

Q. Okay. Well, I guess the record is what it is.

A. (Gorman) I'm sorry, but that -- to add to that, that's how PHP is currently operating. They're not making a 120-megawatt contribution to this 3CP, and NS Power has not incurred additional capacity cost to serve them as though they are. So the amount of capacity that NS Power has incurred to serve its system is being allocated across the customer classes based on their contribution to that 3CP demand. And for PHP, even though there are hours where it will operate at more than 65 megawatts, its contribution to 3CP in this case is 65 megawatts, and out of that 65, only 8 is firm.

Q. Okay. Just a few questions

relating to the revenue-to-cost ratio, Mr. Fitzhenry.

A. (Fitzhenry) Sure.

Q. You had a discussion with Ms. Power. You'd indicated, I think generally, that you're aware that most regulators use, I'll call it a range of reasonableness around one in revenue -- in assessing revenue-to-cost ratios?

A. (Fitzhenry) That's correct. My understanding is that, you know, Nova Scotia has previously approved, you know, R/C ratios between 0.95 and 1.05.

Q. Yeah. And my question relates to other regulators as well. You're aware that that's a common practice amongst regulators in North America?

A. (Fitzhenry) I would say, you know, to the extent that there's rate shock or, you know, issues with cost-of-service gradualism, then those types of R/C ratios might be used. I'm not sure I would -- I know that the 0.95 to, say, 1.05 has been a widely

accepted range from other jurisdictions, but certainly I'm aware -- you know, I'm aware of other jurisdictions that have applied R/C ratios outside of 1.0.

Q. Right. And cost-of-service studies are not -- it's not an exact science?

A. (Fitzhenry) Yeah, I would say, you know, generally that's true. I would just, you know, clarify that in this particular instance, we're coming off a -- you know, a GRA and, you know, a year-long cost-of-service settlement process, where all the parties got together and re-looked at these cost-causation principles and, you know, how to allocate demand costs between capacity -- excuse me; between demand and energy; you know, how they allocate transmission costs. So the only difference between, you know, maybe this proceeding and past proceedings is that this -- these particular -- this particular cost-of-service model is informed by, you know, very recent considerations by all parties.

Q. Okay. But in terms of cost

allocation, it's not an exact science; there's a degree of subjectivity and judgment to it?

A. (Fitzhenry) Yes.

Q. And that's one of the reasons why regulators kind of view cost parity as not a precise point, but a range of reasonableness around 1?

A. (Fitzhenry) Yes, I would agree that some regulators do apply that, you know, principle.

Q. That's -- you said "some," but that's fairly common, isn't it?

A. (Gorman) Yeah, I believe that technology and that cost-of-service isn't precise is fairly well accepted across the industry.

Q. Right. And you're not aware of any regulators who have an absolute requirement that class revenue-to-cost ratios be at 1?

A. (Fitzhenry) I'm not aware, no.

Q. Okay. Those are my questions.

THE CHAIR: Anything arising from

Board questions?

Nova Scotia Power?

FURTHER CROSS-EXAMINATION BY MS. POWER

Q. Just very briefly, Mr. Fitzhenry. You characterized the modelling of the specific costing determinants that were in the Settlement Agreement as necessary because the parties needed a starting point. Is that right?

A. (Fitzhenry) That's correct.

Q. And did BAI support baking these specific costing determinants into the Settlement Agreement?

A. (Gorman) Well, I mean, when PHP agreed with the settlement, it accepted it's ---

A. (Fitzhenry) Yeah, I think we ---

A. (Gorman) --- reasonable that ---

A. (Fitzhenry) I would say, as, you know, consultants, we, you know, supported some things, we had concerns about others, and we relayed that to our counsel and the client, and then they ultimately, you know, informed -- that informed their decision about

whether they enter into the settlement or not.

Q. PHP could have remained below-the-line pending the development on the new tariff with the known below-the-line determinants; correct?

A. (Fitzhenry) PHP -- sorry; could you restate that question?

Q. In terms of how they were modelled for the GRA, they could have remained below-the-line and used those determinants?

A. (Fitzhenry) I think we were looking at below-the-line and above-the-line models, you know, over the course of the process. So, you know, subject to the agreement of all other parties, I guess we could have, you know, proposed that we stay below-the-line, and maybe they would have agreed to that. I don't know.

Q. And that could have been a starting point for development of this new tariff that would still be considered at this hearing today, which

still would have a deferral account that could capture any differences?

A. (Fitzhenry) Yeah, I suppose it could. I mean, there's -- certainly we have, you know, discussions here about, you know, deviations or how to capture this accrual. So, you know, I guess I can't speak to -- I don't know off -- you know, whether moving from a below-the-line to an ATL at this time, or whether moving from, you know, these would have created any less or more accrual to those accounts.

Q. Right. I'm just going to suggest to you that including a cost-of-service result in a Settlement Agreement is because you would anticipate that it would reflect what would be applied in 2026 and 2027?

A. (Fitzhenry) I think we were certainly hoping to become an ATL customer, which is why we were, you know, pursuing modelling with us included in an ATL rate.

Q. Thanks.

MS. POWER: Those are all my questions, Mr. Chair.

THE CHAIR: Consumer Advocate?

MR. MURPHY: No questions. Thank you.

THE CHAIR: Small Business Advocate?

MS. POWELL: No questions. Thank you.

THE CHAIR: Industrial Group?

MS. RUBIN: No questions. Thank you.

THE CHAIR: Board counsel?

MR. MAHODY: No, Mr. Chair. Thank you.

THE CHAIR: Mr. MacDougall, anything arising from Board questions or re-direct?

MR. MacDOUGALL: No thank you, Mr. Chair.

THE CHAIR: Mr. Fitzhenry, Mr. Gorman, thank you very much for your participation in in this proceeding and your testimony. Nice to see you both today. And you're dismissed.

MR. FITZHENRY: Yeah, thank you very much, Chair, and Board Member.

(WITNESS PANEL WITHDRAWS)

THE CHAIR: Okay. Well, I think we're at the end of the day today, so we will resume next Monday at 9:00 o'clock.

--- Upon adjourning

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, M12661.



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Halifax, Nova Scotia
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