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: Monday, September 28, 2026

APPEARANCES:

APPLICANT: **Nova Scotia Power Inc.**
Ms. Mollie Morrie, Counsel, Regulatory
Ms. Kathleen Murray, Counsel, Regulatory
Mr. Blake Williams, Vice President, Legal and Regulatory

INTERVENORS:

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

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

EfficiencyOne
Mr. James Gogan
Ms. Lucia Westin-Eastaugh

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

Nova Scotia Independent Energy System Operator
Mr. David Luther, General Counsel
Mr. Mark Peachey, Director, Regulatory Affairs

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

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

BOARD STAPHP: Mr. Steve Pronko
Mr. Robert Norwood, Public Proceeding Assistant
Ms. Svitlana Lykhina, Public Proceeding Assistant

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Halifax, Nova Scotia

--- Upon commencing on Monday, September 28, 2026, at 10:00 a.m.

THE CHAIR: Good morning.

This is the continuation of a hearing of the Nova Scotia Energy Board relating to an Application by Nova Scotia Power Incorporated for the approval of a tariff for Port Hawkesbury Paper, identified as the Extra-Large Industrial Dispatchable, or ELID, Tariff.

Welcome back, everyone.

Are there any preliminary matters before we get going again today from any party?

Okay, Mr. MacDougall.

(SHORT PAUSE)

MR. MacDOUGALL: Thank you, Mr. Chair, good morning. Good morning, Commissioner Melanson.

Mr. Chair, today we're putting forward the company panel for Port Hawkesbury Paper. Mr. Bevan Lock farthest from you and Mr. John Esaiw closest to you.

Maybe we could have the gentlemen affirmed, and then we'll get them to adopt their evidence?

THE CHAIR: Thank you, Mr. MacDougall.

BEVAN LOCK, Solemnly Affirmed:

JOHN ESAIW, Solemnly Affirmed:

THE CHAIR: Thank you.

DIRECT EXAMINATION BY MR. MacDOUGALL

Q. Mr. Lock, you're the co-Mill Manager at PHP; is that correct?

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

Q. And Mr. Esaiw, you are the Energy Director at Port Hawkesbury Paper?

A. (Esaiw) Yes, correct.

Q. And Mr. Lock, there was evidence filed in this proceeding by Port Hawkesbury Paper sponsored by you and Mr. Esaiw as Exhibit N-3; reply evidence filed as Exhibit N-37, and various responses to information requests. Were those generally prepared under your direction and control?

A. (Lock) They were.

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

A. (Lock) Yes, they are.

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

A. (Lock) I do adopt them as our evidence.

Q. And Mr. Esaiw, you similarly participated in the development of these materials; correct?

A. (Esaiw) I did.

Q. Thank you.

Mr. Lock, I understand you have an Opening Statement, and you can go ahead with that now if you wish.

OPENING STATEMENT BY PORT HAWKESBURY PAPER

MR. LOCK: Thank you, and good morning, all.

Port Hawkesbury Paper LP is a pulp and paper manufacturing facility located in Richmond County, which operates a thermomechanical pulping facility and supercalendered machine page.

Is Nova Scotia's largest electricity customer, with energy demand significant enough that in some instances, the mill's load can represent greater than 20 percent of the provincial power grid. PHP requires energy around the clock on a 24 by 7 basis, even when the mill has no pulp production lines or paper machine running, there is approximately 12 megawatts of demand on site. That includes approximately 4 megawatts that are needed to maintain the shared services required for the Nova Scotia Power Port Hawkesbury biomass plant.

A sister company to PHP, Port Hawkesbury Paper Wind Limited, is constructing the largest

wind farm in Nova Scotia, the Goose Harbour Lake Wind Project, which will add 168 megawatts of wind generation to the grid later this year.

PHP currently takes electricity service from Nova Scotia Power under the Extra-Large Industrial Active Demand Control Tariff, the ELIADC. Under the ELIADC Tariff, PHP pays its incremental costs of service and makes a contribution to Nova Scotia Power's fixed cost. The ELIADC Tariff also provides Nova Scotia Power with the ability to direct PHP to decrease or increase its load, such that Nova Scotia Power's overall system costs can be reduced and the system reliability can be improved for the benefit of all Nova Scotia Power customers.

Being a fully dispatchable load, much the same as a dispatchable power generation facility, comes with its own unique challenges. As such, PHP needed to become highly adaptable in its operation to accommodate this ELIADC structure, tariff structure.

Nova Scotia Power has indicated to stakeholders that the Active Demand Control aspect of the tariff has, in quotes:

> Has provided a value tool in managing supply and demand balance, particularly when real time operations do not go as planned. The ability of PHP to respond to operator dispatch requests in a timely manner has helped avoid exceedances of system operating limits, and also to maintain operating reserves. (As read)

PHP's interest in moving to an appropriate above-the-line cost-based tariff is to provide PHP greater certainty and predictability of its energy costs compared to the below-the-line incremental cost-based structure that includes a contribution to the utility's fixed costs.

In combination with the electricity to be provided by the PHP wind project at a fixed price, PHP is seeking greater certainty in the annual price for non-wind resource electricity, and to reduce the risk of being a below-the-line marginal customer, where electricity prices can vary widely from what is forecast by Nova

Scotia Power. More certainty and predictability in the electricity pricing is an important for PHP as it competes in a dynamic and changing paper market. The approval of a appropriate above-the-line tariff would give an option to PHP to move to a more certain price structure, while continuing to invest in the mill for a long term.

As such, PHP has been in discussions with NSP regarding the terms of a potential above-the-line tariff which would be applicable to PHP since the summer of 2023, up until a few days prior to NS Power's filing of its Extra-Large Industrial Dispatchable, ELID, Tariff application.

While PHP is generally in agreement with the form of the ELID Tariff applied for by NSP, it has serious remaining concerns with various aspects of the proposed costing of the ELID tariff as follows:

A, the use of 57,000 kilowatt winter month system coincident demand for PHP's interruptible load. B, the value of the proposed interruptible credit

for PHP if the Board finds that interruptible load should be greater than zero kW. The use of a revenue-to-cost, an RC, ratio of greater than one for a new above-the-line tariff; and D, the use of forecast energy requirements that do not reflect the most up-to-date assumptions. Regulatory aspects of these issues are each dealt with in detail in the evidence filed by Brubaker and Associates.

PHP is intent on seeking an above-the-line embedded cost-based tariff. However, the issues noted in -- noted above require adjustment in order to actually provide for such a rate. The ELID tariff as filed does not reflect causality, and would overcharge PHP with respect to service provided.

PHP is putting forward its position on these matters consistent with the Settlement Agreement in the 20206/'27 GRA that specifically provided that capital "P" parties could take any position they so choose in this process.

With respect to the applicable

interruptible demand reliance on 57 megawatts of interruptible demand for 2027 is not appropriate, given that this historic demand level was from 2022 and 2023, at a time when PHP's load was subject to dispatch by Nova Scotia Power, and PHP’ load is expected to be at 8 megawatts during times of system peaks.

If the Board determines that PHP's interruptible load is greater than zero at the times of system peak, the interruptible credit needs to be calculated appropriately.

As indicated by Nova Scotia Power, had the Interruptible credit been developed in accordance with Nova Scotia Power's established practice for pricing the interruptible credit based on 57 megawatts of interruptible demand, the appropriate credit would be $13.10 per kVA demand coincident with system peak, as opposed to the $7.67 per kVA applied for by Nova Scotia Power for 2027.

With respect to the issue of Active

Demand Control, ADC, PHP knows firsthand the importance of load flexibility in an ever-increasing variable generation serve system; and, as such, its intention to continue to make its load available to Nova Scotia Power and the Nova Scotia Power System Operator for dispatch and function much the same as the ELIADC Tariff. PHP also intends to remain priority interruptible, as well as being dispatchable. Provision of these elements of the ELID Tariff is, of course, dependent on receipt of renumeration [*sic*] commensurate with the risks and costs that that provision of these resources entail.

PHP anticipates being charged its appropriate embedded cost of service, including a significantly greater contribution to fixed costs than underneath the ELIADC Tariff that reflects Nova Scotia Power's costs to serve PHP, in the same manner as with all other above-the-line customer classes. If the ELID Tariff is approved with the costing adjustments suggested by PHP, PHP will be paying its full cost of service; and, as such,

any energy cost savings which PHP can achieve through ADC should naturally accrue solely to PHP.

As well, PHP alone bears the operational and commercial costs of shifting its load in a manner that is far from ideal from running of the PHP facilities while the provision of ADC will continue to provide valuable reliability benefits to the system as a whole.

In regard to priority interruptibility, to the extent that an appropriate credit is not provided, then PHP will no longer be called in advance of other large industrial customers being held in operating reserve. Rather, PHP would be called in rotation with such other customers, putting those industrial customers at greater risk of interruption.

Thank you for the opportunity to provide this Opening Statement, and we look forward to addressing any questions the parties -- from the parties and the Board.

Thank you.

THE CHAIR: Thank you, Mr. Lock.

MR. MacDOUGALL: Mr. Chair, the panel is available for cross-examination.

THE CHAIR: Thank you, Mr. MacDougall.

Nova Scotia Power?

MS. POWER: Mr. Chair, I'd like to go last, if possible.

THE CHAIR: Sure.

Consumer Advocate?

(SHORT PAUSE)

MR. MURPHY: Good morning.

CROSS-EXAMINATION BY MR. MURPHY

Q. Good morning to the panel.

When I asked my questions I'll ask it to both of you. And between the two of you, you can decide who would like to answer.

A. (Lock) We'll sort it out.

Q. Okay. Thank you.

MR. MURPHY: If you could bring up Exhibit N-1, and it's page 30 of the PDF. You can probably zoom out a little bit, just so we can see the full page.

UNIDENTIFIED SPEAKER: Scaling was really, really weird.

BY MR. MURPHY:

Q. So just on this, this is the Settlement Agreement. You're both familiar with this document?

A. (Lock) Yes.

Q. Okay. And PHP was obviously a

party to this Settlement Agreement.

A. (Lock) Yes, we were.

MR. MURPHY: And if we can go to page 40 of the PDF. Yeah. And if you can scroll down, just show, if possible, to show (a) to (d). That's perfect.

BY MR. MURPHY:

Q. So I have some questions that I'd like to ask about Clause (e), but just to sort of preface that, you know, obviously if you want to have a look at a to A to D to refresh yourself.

(SHORT PAUSE)

BY MR. MURPHY:

Q. Okay. And so Clause (a) there indicates that the Cost-of-Service Study will include 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. And then (b) indicates certain load characteristics for PHP, and suggests that the cost of service was prepared on the basis of those

characteristics. And then (c) refers to:

> The dollar value of the Interruptible credit to be applicable to PHP's interruptible load [and says it] shall be the same as the credit for Large Industrial Interruptible customers.

So on (a) to (c) I guess my question would be these are all terms that PHP had accepted at the time?

A. (Lock) These are all modelling characteristics that we would have provided for that process, and not for the Application that we're talking about today.

Q. Okay. And the modelling characteristics, they would have been used by Nova Scotia Power to develop its Cost-of-Service Study that was filed with the GRA?

A. (Lock) Yes. As indications, of course, with our ability, as it points out in this section here, that any party, Port Hawkesbury included, would have the ability underneath this proceeding to look at those

inputs.

Q. Okay. But to my question, did you agree that those inputs were reasonable at the time?

A. (Lock) At the time to be able to continue with the process with our -- the other Intervenors towards a GRA, there had to be some inputs done. So yes, we did put those forward as modelling characteristics.

Q. And why do you say there had to be some inputs done?

A. (Lock) With Port Hawkesbury's work with the utility to join a group of above-the-line customers, we recognize that the -- all those characteristics would have to be considered at that time with, again, of course, the ability for -- as an individual customer on a on a completely new tariff, would have the opportunity to make sure that those inputs were set appropriately, and the opportunity to agree or not agree to them.

Q. But I guess how does that benefit the parties to, you know, have those inputs on the cost of service if it's -- if they're not fixed?

A. (Lock) Like all customers having forecast to work from and input, there has to be a starting place and some guidance for the utility to be able to provide the service, you know, have the sufficient resources to cover demand, a number of different -- different aspects that would have to be considered at that time.

Q. But I guess if all of those inputs could be changed, then how much of a forecast does that really provide? It doesn't seem like it's something that either Nova Scotia Power or any of the parties would be able to rely upon.

A. (Lock) Very similar to any other customer, the actual energy that's used and the timing of that doesn't always comply exactly with the forecasts that are provided or used. These were simply some -- again,

provided as modelling inputs to achieve a general Settlement Agreement at that time, and in a separate matter.

Q. But there's a difference between the methodology used to prepare forecasts and then the actual result, right?

A. (Lock) Yes. Like every other, be it customer, particularly industrial customers with today's market and everything with tariffs, I don't see that there's any ability for anyone to hold to exactly what they've signed or forecasted or put in for model inputs some two years ago.

Q. And you would understand that the -- these inputs and the impact that they had on the cost of service would have been -- provided a picture, I guess, to other customers of what their allocation of costs would look like if PHP became an above-the-line customer on these terms?

A. (Lock) Yes, there has to be some

picture framing that creates the bounds for everyone to understand. And I think that what we see in this case was there was also the, you know, creation of a deferral account that would help deal with if there were any actuals that ran different than what had been used at that time. So it was -- it's understandably anticipated as it's been verified through, you know, even the setup of a deferral account. If everyone locked everything down, and in perfect foresight, then there would be no need for such a construct, but there is. In this case there was put up in recognition, I think, largely of the number of things that will continue to change throughout the time.

Q. Thank you. And I'll come back to the deferral account in a moment.

MR. MURPHY: So then if you scroll down a little bit to show the more of the -- and potentially into the next page. That's great. You can scroll up a little bit. Thank you.

BY MR. MURPHY:

Q. So then (d) refers to:

> PHP and Nova Scotia Power will complete discussions and analysis of the value of Active Demand Control..., which shall be proposed to be a rider to the cost-based rate.

So this reads a little differently than the other terms. It suggests that it still hadn't been fixed or determined. Is that right?

A. (Lock) That's correct.

Q. Okay. And what was the outcome of those discussions?

A. (Lock) Given the back and forth with Nova Scotia Power, Port Hawkesbury agreed with what the utility to put forward as the calculation of the benefit to Port Hawkesbury of providing that load flexibility service, and we support that in this Application.

Q. Okay. And that's been included in the Application?

A. (Lock) That's been included in

the Application, correct.

Q. And then if you can scroll down to €. And so you might be able to help me understand here. So (e) says:

> [Nova Scotia] Power and PHP shall reflect the foregoing in a written tariff which shall also include a proposal for priority interruptible to be brought forward for approval by the Board later this year to be effective January 1, 2026 [and then it goes on to say] and PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes.

So where it says, "NS Power and PHP shall," did PHP understand that this was an optional commitment to reflect the foregoing in a written tariff?

A. (Lock) Yes, we understood that in the last line of that the "subject to satisfactory conclusion," yeah. And of course, we know that January 1, 2026 that didn't happen. We're here and heading towards January 1st, 2027. Yeah.

Q. Okay.

A. (Lock) So obviously there was lots of discussion and work on those processes.

Q. Okay. And so now when it says those processes, are you suggesting that that's referring to what are your -- what is that referring to; "PHP ADC and tariff processes that will be brought forward for approval..."?

A. (Lock) Sorry; just confirming with John. We, in reading and reflecting on it, believe that that covers all the various operating characteristics and that would be put in place for -- that were included in the Application. And -- yeah, the -- and as it says in that is open to all parties, capital P, in terms of to take any position on that. And that's why we're here today.

Q. Okay. But before we move to (f), I guess I'm just trying to understand the commitment in (e), right? So (e) talks about, "[Nova Scotia] Power and

PHP shall reflect the foregoing in a written tariff..." And so the -- I guess it says, "shall"; both parties "shall reflect the foregoing in a written tariff..." So did PHP understand that it was not obligated to reflect the foregoing in a written tariff?

A. (Lock) So with respect to (e), we did not file a joint tariff. Nova Scotia Power filed the tariff, and we've agreed with some elements and disagreed with others.

A. I understand that. I guess what I'm what I'm trying to understand, though, is where the language says that both parties "shall reflect the foregoing in a written tariff," was it PHP's understanding that it was not obligated to reflect the foregoing in a written tariff?

A. (Lock) I think our position is we weren't obligated to accept all the terms.

Q. And you mentioned that the Application was to be filed by Nova Scotia Power. That's

consistent with prior applications for the ELIADC as well, right? That those were filed by Nova Scotia Power before the Board?

A. (Lock) Honestly, I can't remember if it was a joint tariff in the ELIADC or whether it was just put forward by Nova Scotia Power.

Q. Okay.

A. (Lock) I honestly don't know.

Q. Okay. And what about the most -- I guess the most recent extension, I believe, was filed by Nova Scotia Power. It would have been brought forward by Nova Scotia Power and not jointly by PHP. Is that ---

A. (Lock) I will accept that, subject to check, yeah.

Q. Okay. And -- but were you involved in that process at all?

A. (Lock) Yes, we were.

Q. Okay. And do you recall in, you know, prior to that application being filed, holding a

stakeholder conference with other Intervenors and advocates, stakeholder conference hosted by Nova Scotia Power and PHP?

A. (Lock) Yes.

Q. Okay. And so although the application was filed by Nova Scotia Power, it would have been supported by PHP.

A. (Lock) Yes. The -- that intervenor session that was had and was a -- jointly presented and focused on a lot of the details of how our load was used, and we heard testimony from the System Operator at the time. And, yeah, we both were commenting on how it had been functioning from both parties' perspective as a -- as a reflection on what was happening.

Q. Okay. And so I guess it would -- at the time when you signed off on this Settlement Agreement would you have understood that the intention was to follow a similar process when filing a tariff for an above-the-line rate?

A. (Lock) A similar process to the extension? Sorry.

Q. Yes.

A. (Lock) Yeah, okay. Yeah, we -- this -- these tariffs both work very closely with the utility, and like has been mentioned a few times here in these proceedings, we've worked with Nova Scotia Power since 2023 to come out with a above-the-line tariff that worked for both parties. So -- however, and unfortunately, what was what was drafted in this Application Port Hawkesbury didn't fully agree with. In general we do, in major parts we do, but there are a few specific items that we do not.

Q. Okay. In terms of the process that would have been followed after this would have been signed, and again, with reference to Nova Scotia Power and PHP reflecting the foregoing in a written tariff, can you tell me kind of what steps you took with Nova Scotia Power to fulfil that -- that provision?

A. (Lock) Once again, we've worked very closely with Nova Scotia Power to continue to do various modelling, looking at actuals versus the forecasts from prior years. And so that's what we largely focused on was the reflection of actuals as time rolled on from when the GRA was set and conditions changing since then.

Q. Okay. So the second half of that clause, I guess, indicates that:

> ...PHP commits to taking service under such a tariff on January 1, 2026, or such later date as the Board approves the tariff as being effective, whether on a permanent or interim basis, subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes.

So do you agree that that reference to the "satisfactory conclusion of the resolution of the PHP ADC and tariff processes," that's referring to this process that we're currently engaged in?

A. (Lock) Yes.

Q. Okay. So then we've talked a bit about Clause (f), which is that next provision that you've

referred to. And it indicates that:

> In the PHP ADC and tariff processes that will be brought forward for approval by the Board later this year, it remains open for all Parties to take any position they so choose...

So is it PH -- so I understand PHP is position is the reference to any parties means that PHP can take any position it wants in response to this Application?

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

Q. Okay. And is it PHP's position or understanding as well that any party would also include Nova Scotia Power?

A. (Lock) Yes.

Q. So Nova Scotia Power committing to reflect the foregoing in a written tariff that it was going to file with the Board under Clause (f), also had the ability to dispute its own Application?

A. (Lock) I think if NSP chose to that would allow them, yes.

Q. When did you first become aware that conditions had changed to the extent that you couldn't accept the assumptions that are laid out here in this -- this provision of the Agreement?

A. (Lock) So conditions changing, again, as I mentioned earlier, that what we had provided during the GRA process was some characteristics for modelling purposes that we had asked for. For general understanding and helping in the formation of the Settlement Agreement, for us the conditions were -- hadn't changed. We just had put forward, and with a full understanding through this, as it's identified here in the settlement terms, that we'd be able to dig into those assumptions as we develop the application separately. So there was not a particular date or time of a revelation of things that changed. It's we needed to have something for the utility to model. And we provided that as a -- as a starting place.

Q. But I think you said, when I

asked about the process you follow to reflect the foregoing in a written tariff, that it was through, that through subsequent modelling -- I'm not trying to put words in your mouth, but through subsequent modelling that you realize that you weren't going to be able to put together a joint tariff on this -- on this issue.

A. (Lock) I think that's -- that's yeah, fair. What I said was that as we understood more clearly that -- the utility's position with respect to the 3CP demand that they were using, and simply using what had been provided for modelling purposes and not reflecting what actually had happened during the time of three coincident peaks for '23/'24 or '24/'25, that we realized that there was a difference.

Q. Okay. And when was that?

A. (Lock) I can't tell you the date or -- it was -- I think it was as a result of an IR. I'll look to John here. Would have been done by BA -- in BAI's review in looking for data. I can't tell you when. We

can certainly look that up, if you'd like.

A. Okay. And that'd be helpful if you could provide an undertaking on that.

A. (Lock) Yes, we can.

THE CHAIR: Just for clarity on the record, Mr. Murphy, the undertaking is for a date for exactly what?

MR. MURPHY: For exactly when the -- I guess PHP understood the modelling results to be -- change their view on the parameters.

BY MR. MURPHY:

Q. It's okay?

A. (Lock) Yeah, I think that that covers it. Know enough to -- enough to dig into finding the -- when we had been provided the most recent 3CP evaluation as part of the questions from the BAI.

THE CHAIR: That'll be Undertaking U-16.

UNDERTAKING U-16 - To provide the

date the modelling results changed PHP's view on the parameters

MR. MURPHY: Thank you.

BY MR. MURPHY:

Q. And just while we're here, that would that have been after the Settlement Agreement was signed or before?

A. (Lock) Been after.

Q. Okay. And was it -- I believe the GRA was filed on September 18th, 2025. Was it -- and this Settlement Agreement was signed on August 29th. So was it between those dates or was it -- would it have been after September 18th?

A. (Lock) I mean, I think we'll answer that as part of the Undertaking 16. I really don't know.

Q. Can't say?

A. (Lock) Can't say.

Q. Okay, thank you. And I expect you'll have a similar answer to this question, but when did PHP first indicate to Nova Scotia Power that its views on the load parameters was -- had changed?

A. (Lock) We'll have to take that as an undertaking. I can't provide any data, but, once again, I -- we were in a process of looking at the appropriate things to put in this -- not the Settlement Agreement, but the tariff, which we had the ability to take any position on. And I know as a -- you know, that -- I have no idea when the views of any other party changed, or parties. All I can tell you is that as a sophisticated energy user, and very much integrated with this Nova Scotia system, I would never sign off on a commercially unreasonable position without the full visibility of what was -- what was going to happen, and what has been happening with respect to 3CP.

Q. Okay. I guess maybe we could add that to the prior undertaking, to confirm -- I guess it

would be when they became aware of the change and when they would have advised Nova Scotia Power.

THE CHAIR: Are you okay with including that as part of Undertaking U-16, Mr. Lock?

MR. LOCK: We are.

THE CHAIR: Okay, thank you.

Mr. Murphy?

MR. MURPHY: Mr. Norwood, if you can scroll down a bit to show more of paragraph (g). That's great. You can zoom in a bit on that, if you'd like.

BY MR. MURPHY:

Q. So we talked a little bit earlier about the deferral account and the circumstances where it may be necessary. And the first circumstance is noted in (a) and it says:

> where a Board decision on the PHP tariff, including the Active Demand Control rider, differs from the above the line PHP tariff assumptions included in the 2026-2027 GRA;...

So you would agree with me that that's

referring to the possibility of a Board -- of the Board not accepting what was proposed by Nova Scotia Power?

A. (Lock) Well, yes.

Q. Yes, okay. And then the second is:

> Where, for any reason, the PHP tariff is not available for PHP to take service under it as of January 1, 2026;...

So that's pretty broad -- pretty broad provision; agreed?

A. (Lock) Yes, it is.

Q. Yes. And then the last is where:

> PHP determines that the PHP ADC and tariff processes outcome is not satisfactory.

And earlier you had described the PHP ADC and tariff processes as being this process, the Board's process, right?

A. (Lock) Correct.

Q. Okay. I guess what I'm wondering is if PHP wasn't at least committed to accepting service

under the tariff on the terms that were set out here, why bother going through with the process of having NSP create a deferral account?

A. (Lock) Sorry; can you reframe the question?

Q. Sure. So the deferral account, as I understand it, was created on the assumption that PHP was going to accept service on these terms, and for the possibility where if they didn't accept service that the cost could be absorbed by the other customers.

A. (Lock) Well, we're not speaking about how the costs are absorbed or if there was cost. I think what it talks about if there's revenue variances and how those would be. As my colleague from BAI went over last month, you know, it's not a foregone conclusion that any of the changes that -- or the outcomes that are not satisfactory would have any particular costs. But, once again, I think the deferral account was set up with full recognition that this process was ongoing, and there's a

number of things that could change and that would -- from a variety of different scenarios, including the ones that you just read out.

Q. And so the cost difference, I guess, between PHP an above-the-line tariff that is reflective of the terms that are in the Settlement Agreement versus the terms that -- I guess the changes that PHP has proposed in response to this Application, do you agree that the cost difference is material?

A. (Lock) I can't comment on the materiality of any -- of the changes; we don't have a final tariff in this case.

Q. But I'm assuming the cost, from PHP's perspective, would be material because you wouldn't want to absorb those costs yourself?

A. (Lock) Once again, we don't have a final approved tariff, so I can't comment on, really, the materiality of it. We can say that the aspects that we are in disagreement with are significant enough that we

are not willing -- we were not willing to go with Nova Scotia Power in this Application. And we continue to have, and challenge, the few aspects that have been in the Application, knowing our business very well. And as I said earlier we are extremely, you know, commercially sensitive as a large customer, and concerned about having, as we wanted to proceed with, and that was an above-the-line that would stabilize for the longer term and simplify the aspects of a below-the-line, moving to above-the-line rate. So we remain committed to that, and we're paying significantly more to the Nova Scotia Power system in terms of fixed costs, and this move to above-the-line does that. And we remain committed to providing that significant increase. And of course it's a significant cost to us, but we believe that if the aspects that we put forward, with respect to getting appropriate credit for the demand response that we are actively providing, and appropriate treatment as a priority interruptible customer and not just having a number applied from the GRA that

does not apply or is not based on cost causality. So we're focused on cost causality and we get behind that. But what we believe was put forward does not respect that.

Q. And the current extension of the ELIADC that's set to expire at the end of this year?

A. (Lock) Yes, the extension.

Q. The extension, yeah. And I guess as I understand it, based on the evidence that's been put before the Board, that if PHP is not happy with the outcome of this process, that it may choose not to accept service under the ELID Tariff.

A. (Lock) Correct.

Q. Okay. And so what does PHP envision happening, then, by January 1st, 2027? I mean, that's coming pretty soon.

A. (Lock) We expect that there will be coming up with an appropriate tariff, whether that's the -- us joining and being a LIIR customer, a Large Interruptible customer, or -- we don't -- we don't have an

idea of what the outcome was.

We remain committed to making this Application that's present today and that we're discussing work. It just has to be recognized, the value that we provide, the significant changes that we've gone through to go above-the-line, and respect the cost causality and the cost-of-service piece.

The ratemaking that has been put forward is very clear on how to approach cost of service. We believe the Application doesn't get that right. And we are going to work with everyone here so that we can get a greater understanding. We feel that what we're doing is based on good, sound ratemaking, as well as providing solid value in terms of our DR abilities that has been really working well for the utility, as we've heard from not just the utility, but the System Operator directly on how it's used.

Q. Okay. And you mentioned the LIIR. Is that something that you're considering if this

tariff isn't something you'd like to use?

A. (Lock) I think probably considering is too strong, but, you know, looking for options, that may be an option.

Q. Okay. And what about an extension of the ELIADC?

A. (Lock) I think our perspective has been that that is a would -- be a difficult form, the below-the-line form to work out with the addition of the PHP wind as part of our gross electric electricity supply. But never say that couldn't get there, but from our objective to go above-the-line makes that process much more clean and straightforward, as Mr. Ferguson and others on the panel from Nova Scotia Power last week had spoke to this, the whole reason why we're here.

Q. Okay. Have there been any discussions with Nova Scotia Power about a, you know, potential contingency plan if you decide not to take service under the ELID?

A. (Lock) We really feel, once again, that we can get from here to there ahead of next January, or this January -- this coming January on this rate. So, you know, being committed to that we've not spent time coming up with contingency plans. We think that the framework that has been working, that we're putting forward is sound; some of these aspects, final aspects to ensure are fair and just and don't impact our business in a -- in a negative way.

Q. And I appreciate that. And it's hard to say what the future holds until you get a Board decision. I respect that. I guess what I'm also worried about is that it may be some time before we get a Board decision and then it's going to be coming near the end of the year, and there may be a sort of frantic ELIADC application that hasn't been well-considered. And so whether that's something that PHP is concerned about and wants to try to address.

A. (Lock) As I said in my Opening

Statement, Port Hawkesbury is the single largest electricity user in the in the province. And of course, we're concerned if proceedings and things get waylaid. So we definitely -- you know, it is on our concern along with tariff demands south of the border and many other business aspects. So this being a large -- the single largest piece of our cost structure at the mill, of course we're concerned, yeah.

Q. Thank you, gentlemen, appreciate your time.

A. (Lock) Thank you.

Q. Thank you.

THE CHAIR: Small Business Advocate?

(SHORT PAUSE)

MS. POWELL: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MS. POWELL

Q. Good morning, gentlemen.

As with my friend, I'll just direct my questions to the panel, and you can decide who best to answer. And as often happens, my friend has made my job a little easier. I just have a couple -- a few questions to clarify. Some of the items I was going to go over have been addressed already this morning.

So just in terms of referring back to your Opening Statement, if I may.

MS. POWELL: So this is Exhibit 41, Mr. Norwood, and we're looking at page 3. Yeah, brilliant.

BY MS. POWELL:

Q. And I'm just going to -- you mentioned in your Opening Statement, just in that first paragraph at the top of the page:

> In regard to priority interruptibility, to the extent that an appropriate credit is not provided then PHP will no longer be called

> in advance of other large industrial customers being held in operating reserve. Rather, PHP will be called in rotation with such other customers, putting those industrial customers at greater risk of interruption.

So I just wanted to ask, regarding you making the statement there, "Rather, PHP would be called in rotation with the other interruptible customers." So just to confirm; so if you -- if this were to occur is -- are you okay with that, that you will be called in rotation?

A. (Lock) Yes, we would be fine with that. Underneath the interruption protocol, our load would have to be restored within 16 hours of it being interrupted. And we, like any other of the customers in that class of -- with interruption, would get called in rotation, recognizing that our load, you know, from time to time, and probably not at the tight periods, but can be as much as the whole priority interruptible class within the Industrial Group.

Q. Thank you for that clarification.

I just wanted to ask you something related to the evidence that was put forward by your experts.

MS. POWELL: So perhaps we could go to Exhibit number N-2, Mr. Norwood.

MR. LOCK: While we're bringing that up, if I may, with respect to the interruptibility, that -- that's what we've been doing to date, has been priority interruptible, the ELIADC Tariff; we had been priority interruptible. I don't know if that that helps or...

MS. POWELL: Thank you.

MR. LOCK: Okay.

MS. POWELL: And I'm looking at PDF page 10 of 34. Actually, I've gone too quickly, I apologize. I was writing on the other side of the page. I'm actually looking at PDF, page 29. Sorry Mr. Norwood, and sorry if that made people dizzy.

And I'm looking down at lines 18 to

21, so if we could scroll down to the bottom of that, that would be great.

BY MS. POWELL:

Q. And in this evidence that was filed on the company's behalf it states:

> Furthermore, the company notes that these ultimate energy charges remain subject to potential changes depending on the outcome of ongoing court proceedings regarding PHP's responsibility for costs related to the Maritime Link Federal Loan Guarantee.

This is a reference, as you know, to the Maritime Link court matter, which at the time the evidence was filed was still before the courts. However, we know that since then, in April, the decision came out from the courts. So in light of this statement what changes do you see occurring?

A. (Lock) Changes to exactly what.

Q. So if -- we maybe it's fair to look back. Early in, it talks about the energy charges and it talks about -- so maybe if we scroll back up, in

fairness. Sorry. And it's talking about the energy charges. But then it says, "subject to potential changes," and we're just trying to understand, recognizing that at the time this was written it was before the courts. We have a decision. And we're just trying to understand what is meant by that wording in the evidence of your experts.

A. (Lock) We'd respect the Court's decision with respect to the costs.

Q. Thank you.

MS. POWELL: And, Mr. Norwood, if we can now go to PDF page 10, that would be great. Thanks. In the same exhibit, and we're looking at lines 16 to 19. Thank you.

BY MS. POWELL:

Q. In this part of your evidence from your expert consultants, it states:

> NS 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 and to interpret PHP down to the firm demand level with only 10 minutes' notice.

So this this refers to incurring increased operating costs. And so has any analysis been done of those proposed increased costs that are referenced there?

A. (Lock) The straightforward is yes we've done -- I wouldn't -- analysis. We do do cost reviews regularly on breakdowns, on impacts to our mechanical equipment that are influenced and impacted by this starts and stops and the frequency of those that occur when we are a dispatchable customer like we have been in the ELIADC and like we're talking about for the ELID.

So a detailed analysis, looking at each of those aspects, we've not put a full wrap on it because of the complexity. I can provide you some general idea of what it is, but very similar to any large

generation plant, you know, cycling. The first thing that comes to mind is not making customer orders and having to change modes, transportation modes. We ship most of our product optimally by rail if we have to ship by truck. And I think everyone recognizes today what the cost of diesel is to move product to its market. And our market being in the United States, as far away as California, there can be some significant costs when you take one train car and break it down into three truckloads that have to get to California in two days.

So there's -- that's the first one that can happen. How many times that happens, of course, changes by season, by time. But it is front of mind.

After that is the impact on the equipment. So like turbines or turbo generators that the utilities use to and their reliability, what we have is large, synchronous motors that when they go to start up, there's a massive inrush of electrical current which heats up the windings. When you do that over successive times

and more than the ABB, the provider of those -- each of these motors are 2 to $4 million. You are reducing the life, or in the electrical terms, increasing the frequency of the L4 or a specific test that each of those motors has to be taken off, serviced, and looked at.

So the other thing is, of course, with starts and stops of, you know, starting up a paper machine that runs on average over 100 kilometres an hour. So similar to stop and go traffic, every time you put your foot on the accelerator, or take it off and come to a screeching halt, there is a risk. And we've incurred a damage to our wires, which is part of the paper machine fabric, because of quick stops. We've also reduced the -- seen of reduction of life in those wires compared to pre-variable loading.

So many, many, many factors to be able to compile to give you a fulsome analysis. So I guess straight up, we've not itemized all those because of the serious number of items, but that gives you, hopefully,

will give you a little flavour.

Q. Yeah, thank you. And in what is written in your expert's evidence, and you may have touched on part of that in your response, it also talked about incurring production delays. So can you just expand on the incurring production delays? I think we can infer from some of what you've said, but if you could just clarify for the record, that would be great.

A. (Lock) Sure. The production delays could come as a result of a failed start-up, as I mentioned on the paper machine, maybe we -- what we call pulp passing. So it plugs up certain aspects and takes hours to clean and be able to get back to paper production.

So those things as a -- if we were running continuously or on a more continuous basis, those occurrences are greatly reduced. It's only during that start-up that there can be some fluctuations in the pulp that's being fed forward to the paper machine.

Also, because of the delays, when you look at some of the last couple of years in terms of January's and February's, we -- for example, we were down six days in January this year for -- continuously, and the customers that we serve, which we had production delays that impacted us and we had to rush all that paper because our customers are of all different sorts, and they have a last data change of two weeks. So although we arrange a general annual of paper for that customer, they can choose which printing house it goes to and they -- and which basis weights and what's characteristics up to two weeks before expecting delivery in their respective printing plant.

So we have a very tight time window, and when you take out, you know, a significant number of down days, for example, because of system -- tight system conditions, we've incurred production delays and costs because of that.

MEMBER MELANSON: Just on that point,

if I could step in?

MR. LOCK: Yeah.

MEMBER MELANSON: What you're talking about there is actually when you're dispatched down and you have to delay your production, is that what you're talking about?

MR. LOCK: Yes, Mr. Melanson. Yes, that's mainly the -- those longer periods, but the shorter ones too. We run -- we have 1,500 different role sizes of paper. So very, very specific. Unlike copy paper or toilet paper, it's not one size fits all. So very specific. So if we -- and the paper machine, to be consistent, we have to run through thinner papers, up to medium weights to high weights. We can't go from high to low, so we can't -- it takes a long time to turn the ship around. And that planning gets very chopped up by even, you know, a 12-hour delay or something like that on a -- on a critical order. Yeah.

MEMBER MELANSON: I just want to make

sure because in the first part of the questioning it ---

MR. LOCK: Yeah, it was mechanical.

MEMBER MELANSON: --- mechanical, but this is different. Yeah.

MR. LOCK: Yeah. Sorry.

MS. POWELL: Thank you.

If you just bear with me a moment.

(SHORT PAUSE)

BY MS. POWELL:

Q. Thank you, gentlemen, those are my questions.

MS. POWELL: Thank you, Mr. Chair.

THE CHAIR: Thank you.

Thank you. Industrial Group's up next but it's 10 after 10:00, so we'll take our mid-morning break now and come back at 25 after 10:00.

Thank you.

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

--- Upon resuming

THE CHAIR: Okay, thank you.

Ms. Rubin, I think we're ready to go whenever you're ready.

MS. RUBIN: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MS. RUBIN

Q. Mr. Esaiw, you've been sitting quietly over there during all these questionings, so I just wanted a little clarification or explanation. What do you do as Energy Director at Port Hawkesbury Paper?

A. (Esaiw) I guess there's a few aspects to the role. Overseeing -- well, I've recently transitioned, I guess, is what I would say first, from a full-time to a contract employee. So I'm -- I guess we've heard semi-retired in here before, so I'm also on that on that stage. So scaled back a little bit, but regulatory matters, energy supply, commodity activity when we need supply for gas, things like that. And then just really taking a lot of direction as a contract worker now for certain projects, overseeing certain aspects of the Shared Services Agreement with Nova Scotia Power and other commercial agreements with Nova Scotia Power, as a flavour for what I do.

Q. Okay. And that Shared Services

Agreement, that relates to the steam sales and how the energy is allocated and the costs for the -- I'm simplifying and probably missing nuances, but in relation to the Port Hawkesbury Biomass Plant?

A. (Esaiw) Correct, yeah. The steam supply service and the related energy balance.

Q. Right. Okay. And do you have any role in the scheduling under the ADC?

A. (Esaiw) No, not scheduling.

Q. Okay. Do you have any role in relation to the Active Demand Control?

A. (Esaiw) Not any longer. I'd say previously, yes, but not any longer.

Q. Okay. What was -- what was your previous role?

A. (Esaiw) Well, we would receive the dispatches from Nova Scotia Power. That would get disseminated. It's a -- it's an email we get, so that gets disseminated to multiple employees inside the mill.

And then if there was any communication with Nova Scotia Power that would be me or someone reporting to me that would be in communication with them.

Q. Okay. Well, I'll -- I will have some questions about those communications and the process later. But so you can you speak to the period from when the ELIADC was in place up until the time you became a contractor?

A. (Esaiw) Yes.

Q. And since you became a contractor, you said you're not responsible for that. Who is?

A. (Lock) Currently that's our TMP superintendent. So just to clarify, John's role was largely, you know, in monthly reporting and the FAM accounting of the ADC codes, things like that. So data review, quality assurance, I guess you could say, but the day-to-day conversations would be the TMP operator, with either the marketing desk, Nova Scotia Power Energy

Marketing team or the -- or ECC, Energy Control Centre, would be operators or the front-line supervision in the TMP area, which John worked closely with the TMP Manager if there was issues but also in the coding hour by hour of -- and checking the data from the various logs and log forms. So he can speak to the log and -- for those times.

Q. Okay. Thank you, Mr. Lock.

Now, I just wanted to follow up very briefly on some questions about the Settlement Agreement.

MS. RUBIN: And now, perhaps we could turn up Exhibit 46, which was the PHP DR 4.01 in the General Rate Application. Right.

BY MS. POWELL:

Q. Now, this was a request from Port Hawkesbury Paper that Nova Scotia Power provide a Cost-of-Service Study with PHP as an above-the-line customer with certain specified billing determinants; correct?

A. (Lock) Modelling characteristics, and I guess above that the determinants that would be

included for modelling purposes, yeah.

Q. Right. I'm just reading the words of the request:

> ...provide a [Cost-of-Service Study] with PHP as an above-the-line customer with the following billing determinants:

That was the request.

A. (Lock) Correct.

Q. Correct. And you can see those are numbered 1 to 4 there. It says, "PPH's firm load will be modelled at 8 [megawatts] at the 3 coincident peak"?

A. (Lock) Number one, yeah.

Q. And number two is that:

> PHP's interruptible load will be modelled at actual PHP metered load at the time of NS Power's 3CP [and then it says] (65 [megawatts] for this model).

So what that is, is that the interruptible load is modelled at the PHP metered load. So it's 57 which would be 65 minus firm eight; correct?

A. (Lock) Correct.

Q. And then it says:

> Energy at 810 [gigawatt hours] based on PHP forecast usage consistent with its current below-the-line usage in NS Power's [Cost-of-Service Study] model.

A. (Lock) That's what it says.

Q. Okay. And:

> The proposed billing determinants for the [Cost-of-Service Study] model should be applicable to the BCF model as well.

A. (Lock) Correct.

Q. Right. So it was intended that not only was this going to be for modelling purposes when we were looking at cost-of-service methodology, but you also wanted this to apply in the base cost of fuel model for FAM purposes; correct?

A. (Lock) Correct. At that point in time, those were the numbers in terms of the energy expected and forecasts. And today we're at a different energy forecast. But at that time, yeah, that characterized it.

Q. Yeah, okay. And so that was my

question is, what was the basis for requesting each of these billing determinants that are listed there?

A. (Lock) Sorry; the basis for...? sorry.

Q. Yeah.

A. (Lock) I don't quite understand.

Q. I mean, I can guess that the forecast energy of 810 is based on your most current forecast of the energy requirements of the mill, based on its paper order and its projections. Is that...?

A. (Lock) No, the most recent forecast is 774 and not 810.

Q. At the time?

A. (Lock) Yes. Sorry. But, yeah, to be clear, at the time that had been based on informed by the prior year. So that that's what was used at the time, yeah.

Q. Okay. And so that was my question. What is the basis for requesting each of these

figures? Why did you ask that PHP's firm load be modelled at 8 megawatts at the three coincident peak?

A. (Lock) Because underneath the ELIADC construct, Nova Scotia Power has the keys, in terms of its demand at any one time or any hour within the eight, six -- 70, 87, 60 hours throughout the year. So our feeling always has been is they would place our load and -- or take our load off at times of coincident peaks unless, as we heard from Dave before, that if it was a high wind event, even though it might have been a high load event, if the high wind may be up higher, which, you know, has occurred.

Q. Okay. And you asked that the interruptible load be modelled at 57, which would be the 65 minus the eight.

A. (Lock) We were looking, at that time, for the model outputs and, yeah, to be characterized at that level.

Q. Yeah. Why? Why 57?

A. (Lock) Largely informed, once again like the 810, from what had been seen using the cost modelling and the appropriate cost causation determined by the Board in terms of selection of 3CPs. And we look back at 2022 to 2023, and for those years, the average was 65, or as you point out, net 57. So just like today, when we look back and use the same principles, we would use 24 and 25 and come up with 28 megawatts. So for at the time, that had been indicative of what it was, yeah.

Q. Okay. Now, we heard evidence the other day that that 65 was a carryover from the Stern Study in 2012 in the Load Retention Tariff. You were here for that evidence?

A. (Lock) We were.

Q. Yeah. And Mr. Lock, were you an employee at the mill when the Load Retention Tariff was applied for and approved by this Board?

A. I was an employee at the time; I was not responsible when the application was going in.

But shortly after, when it was determined that it was not possible with the price pairs -- price quantity pairs, I became involved because I was managing TMP at the time and recognized that some of the -- that wasn't going to be possible and came up with the reworking of the LRT in the first instance in 2012. That was really early 2013, I guess, is when I would have started.

Q. Okay. And do you have a familiarity with that 2012 Stern Study?

A. Yeah, I'm familiar with the study. And at the restart of the mill was very involved. I had been there during the period of shutdown from the previous ownership and was part of constructing that go-forward plan, so I am. Sixty-five (65) really was not ever intended to be, I can say from having been personally involved in writing the details in that, it was to characterize really just two aspects. That's our bleach plant operation and the paper machine operation. To sustain paper making there's a whole series of different

load levels. But that's where the 65 originated in that document was characterizing the load that various -- various different equipment configurations, but not -- never intended from when we wrote it to represent some sort of interruptible load.

Q. Okay. So that 65 megawatt is entirely unrelated to the numbers that have been put forward and modelled?

A. (Lock) Correct.

Q. From your perspective, anyway?

A. (Lock) From my perspective, having been there in the -- when that plan was being put together for the restart, unrelated, correct.

Q. Okay. So a bit of a red herring to even go back to that?

A. (Lock) Yes. That's my personal opinion and view from having been there, yeah.

Q. And in requesting these billing determinants, these inputs for the modelling, are you

suggesting that 65 megawatts reflects PHP's baseline load absent dispatch?

A. (Lock) No, I'm not.

Q. So then the converse, the 65 megawatts does reflect dispatch?

A. (Lock) The 65 reflected 2022/2023 three coincident peaks, which is the chosen methodology in the Cost-of-Service Study for determination of peak demands.

Q. Right. And those peaks achieved during that time reflect dispatch directions?

A. (Lock) Correct.

Q. Yeah.

MS. RUBIN: Now, Mr. Norwood, could I get you, please, to turn to Exhibit N-1, Attachment 4, PDF 41? This is the Settlement Agreement. And perhaps if you could enlarge it a little bit? (e). Okay.

BY MS. RUBIN:

Q. And my friend has asked a lot of

questions about the Settlement Agreement. I don't intend to cover the same territory, but just wanted to refer to subsection (e), which states that:

> NS Power and PHP shall reflect the foregoing in a written tariff...

And then the last part is -- it says:

> ...subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes.

Correct?

A. (Lock) That's as it's written, correct.

Q. Right.

> ...and PHP committed to taking service under [a tariff] such a tariff on January 1, 2026, or such later date as the Board approved the tariff as being effective...subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes.

A. (Lock) It was Port Hawkesbury Paper's intention to become a above-the-line customer as of January 1st, 2026, and that that did not happen. And that that's what we're here at this hearing to determine

is see -- subject to a satisfactory conclusion of, and resolution of, this process.

Q. Right. So PHP commits to taking service and PHP's commitment is subject to satisfactory conclusion of the resolution of the PHP ADC and tariff processes. That's -- that's the condition on PHP' commitment, correct, in subsection (e); that's the wording.

A. (Lock) In that section, just for context, we were committing to working with the utility and above-the-line tariff. But as has been brought up in earlier review that we really have -- believe that what is written in there, that we will be able to take whatever position any party -- like any other party of this -- in this rate hearing. But our commitment was going above-the-line, which we're attempting to do, but we can take any position.

Q. You're saying your only commitment was to go above-the-line?

A. (Lock) Our general commitment, is what I'm saying, was to work with the utility to put in place an above -- an appropriate above-the-line tariff, one that, you know, followed a cost causality and the terms of the Cost-of-Service Study.

Q. Okay. If we could turn to your evidence, please, Exhibit N-3, page 12.

MS. RUBIN: N-3, page 12. Oh sorry that -- N-3. Lines 10 through 13. Sorry.

MR. LOCK: Document page 12. Yeah.

MS. RUBIN: Sorry, not PDF page 12. There you go.

BY MS. RUBIN:

Q. All right. Now, that says:

> Unless PHP's areas of concern are addressed by the Board in a satisfactory manner it is unlikely PHP will proceed to accept service under the ELID Tariff. PHP would need to undertake the development of below-the-line tariff with NS power that meets the mill's needs if it chooses to not accept service under the ELID.

Okay. And that kind of satisfactory language, where you say, "in a satisfactory manner" that that kind of echoes the condition in subsection (e), "subject to satisfactory conclusion; correct?

A. (Lock) Correct.

Q. Yeah. And then the Consumer Advocate asked a question about that.

MS. RUBIN: And if I can turn to Exhibit N-12, which is Consumer Advocate IR-5. Sorry; I don't have a PDF number for this. It's IR-5. There we go.

BY MS. RUBIN:

Q. So there the Consumer Advocate extracted that evidence, and then they asked:

> What does PHP consider satisfactory in addressing the concerns it raised to accept service under the ELID tariff? Does PHP require that all its recommendations are fully accepted or does PHP have any flexibility in this respect?

And the answer says that:

> PHP will need to review the ultimate Board

decision to determine whether it generates a tariff that PHP will proceed to accept service under.

Is that PHP's current position as well?

A. (Lock) It remains so, yes.

Q. So is it -- is PHP's position that whether the ELID dispatchable rider and tariff processes have reached a satisfactory conclusion within the meaning of subsection (e) is to be determined -- determined by PHP itself, based on PHP's own assessment of whether the Board's decision addresses PHP's areas of concern?

A. (Lock) There is a lot in that question. Can you just break it down for me?

Q. Yeah. So under subsection (e), it said you committed to accept service subject to reaching a satisfactory conclusion. That was the language in the Settlement Agreement, subsection (e).

A. (Lock) Yeah.

Q. And so my question was, is that satisfactory conclusion based on PHP's own assessment of whether the Board's decision addresses PHP's areas of concern?

A. (Lock) No. I think in subsection (f) of that Settlement Agreement, it also points out that it's open for all parties to take positions they so choose. We, like any of the other parties are, in (e), outlining that we're looking to try to make sure the appropriate billing determinants and reflective forecasts of today, not of prior discussions around the GRA, are applicable for what is the largest input cost to the company.

Q. Okay. Mr. Lock, listen to my question. Okay? So the question referred to the commitment in subsection (e), where PHP committed to take under the rider, and -- once the dispatchable rider and tariff processes have reached a satisfactory conclusion. We just worked through that language; that's the language

in subsection (e).

My question with respect to subsection (e) and the language of committing once there's a satisfactory conclusion, is that satisfactory conclusion based on PHP's own assessment of whether the Board's decision addresses its areas of concern. Is that how PHP reads subsection (e), that it determines whether its areas of concern have been addressed, and only then is there a satisfactory conclusion?

(SHORT PAUSE)

MR. LOCK: Sorry. Just conferring on the -- on the interpretation from PHP.

I think in looking at subsection (e) alone, you know, is difficult to take out of context of the rest of the settlement terms. So I'm struggling to answer your question directly. We believe that it's Port Hawkesbury decision alone to accept the tariff that comes out or not, we -- and we believe that we -- what is written in there and what we've answered in IR-5 is that

we're going to have to review the ultimate decision from the -- from the Board, whether or not it is something that we can proceed to accept service under.

So I guess, yes, we will make the final decision based on whether it's commercially acceptable and whether it's operationally acceptable for us to take service underneath that -- this rate.

Q. And is it an all or nothing outcome? Like, does the Board need to accept all of the revisions requested by PHP in order to have a satisfactory conclusion?

A. (Lock) I wouldn't characterize it as an all or nothing. We're here, I think, trying to build consensus and an understanding of how this new rate form would work and treat PHP fairly with respect to the terms and conditions underneath this service. So of course there's opportunity to make appropriate changes and that we'll review at the end with the Board's decision and make a determination whether we can accept service or not.

Q. Now, BAI provided evidence that at the time the Settlement Agreement was signed, it had communicated to PHP that it was not satisfied with the costing determinants that were included in the GRA. You recall that evidence?

A. (Lock) Yes.

Q. Okay. And do you affirm that evidence? You had information that BAI, at least, did not agree with the costing determinants that had been included as part of the Cost-of-Service Study embedded in the GRA and formed part of the Settlement Agreement?

A. (Lock) Yes.

Q. And can you confirm that as of the time the Settlement Agreement was signed, PHP had not communicated to other intervenors that PHP was dissatisfied with the costing determinants included?

A. (Lock) I believe in running up to having the Settlement Agreement signed by all parties that it was known, and we provided the input that we were not

satisfied.

Q. Okay. And can you ---

A. (Lock) But recognizing that what we've just gone through, and (e), (f), and (g), the settlement terms that provided us the ability to take each of these and work them through in this Application, we were satisfied significantly to sign the Settlement Agreement.

Q. I don't think I'm following you. What's the distinction you're making there at the end?

A. (Lock) That ahead of signing the Settlement Agreement, we were aware that there were aspects that were being modelled that we did not agree with the approach, and that to be able to move things forward, as in all settlements between parties, we accepted those, along with the caveat that PHP would have the ability, like any other party, to take any position we so choose, including whether or not the ADC Tariff filings are consistent or inconsistent with the structure. So as

outlined in (f) of the Settlement Agreement.

Q. And did you ask NSP to model, in DRs or otherwise, for the benefit of all the Intervenors so that they would understand the cost implication, alternative billing determinants from what we saw in the Exhibit N-46?

A. (Lock) Just a moment.

Q. And just to clarify, I'm asking in advance of the Settlement Agreement being signed, not following and your later discussions with NSPI in order to make this filing. I'm asking in advance.

A. (Lock) There's been a lot of water under the bridge since then, so I'm struggling to confer here with John on what we would have asked Nova Scotia Power. I don't have a recollection of what additional things. Certainly around the interruptible -- the priority interruptibility was one that we had voiced concern about alignment with the process, consistent with the Industrial Group. But -- and I think we did ask to

see what it would be if you used the proper cost of service in terms of our particular rate class, but I don't remember exactly when that was.

Q. If I suggested to you that there's no DR on the record where PHP requests different billing determinants than the forecast energy of 810 for a load of 8 and the interruptible load model that's 65. Would you accept that subject to check?

A. (Lock) Yes, subject to check.

Q. Okay. And perhaps I could get an undertaking from you that if there is, in fact, a request from PHP predating the Settlement Agreement to model alternative costing determinants that it could produce that.

A. (Lock) That's clear. That's fine with us.

THE CHAIR: Undertaking U-17.

UNDERTAKING U-17 - If there is, in fact, a request from PHP

predating the Settlement Agreement to model alternative costing determinants, to provide same

BY MS. RUBIN:

Q. Okay. Now, you mentioned the interruptible tariff -- sorry; interruptible credit and the priority value. And you said that you -- there was some discussion about that?

A. (Lock) Yeah. I was simply reflecting on when that discussion had happened in an attempt to answer your earlier question, which of course is subject to check now, U-17.

Q. Right. Okay. And then going back to my other question, I had asked whether PHP had communicated to other Interveners that PHP was dissatisfied with the costing determinants. And you said you're certain it was. Was that -- am I correctly recalling what you just said?

A. (Lock) That's my recollection.

Q. Okay.

A. (Lock) Subject to check, but yeah, that's my recollection.

Q. Sure. And how was that communication done?

MR. MacDOUGALL: Mr. Chair, if I could interject for a second? These questions are now getting into various aspects of the negotiations of the Settlement Agreement. I've let them go pretty long, but, you know, this was a Settlement Agreement done in confidence between various parties. And now one party is trying to bring -- pick certain aspects of it to come out. This was a long process with many, many positions by many, many parties at many, many times, that my understanding, was meant to be confidential. I just don't think we could go any further, if this is going to continue along this line of what happened between the various parties who were signatories to a confidential Settlement Agreement.

THE CHAIR: Okay. We had this discussion a little bit last week, and so the Board does have some concerns about getting too far into Settlement Agreements. The question that was just asked is identical to the one that was allowed last week to the other panel. So in terms of this particular question, I think we'll allow it.

MR. MacDOUGALL: Thank you, Mr. Chair.

THE CHAIR: Could you just rephrase the question again? Sorry; we're just a bit lost here.

BY MS. RUBIN:

Q. I asked how is that communication done? Was it in writing?

A. (Lock) Again, I can't recollect if it was done in writing. There were a lot of hurried discussions, both verbal; I do remember a number of verbal exchanges with you and Patrick Bowman. So a variety of things were brought forward by a variety of parties.

With respect to written, I can't

honestly say. Don't have a clear answer, yes or no, to that.

MS. RUBIN: Mr. Chair, could I get an undertaking for those written communications, if any, in which PHP expressed dissatisfaction with the costing determinants that are embedded in the Cost-of-Service Study for GRA settlement purposes?

MR. MacDOUGALL: Mr. Chair, can I get some clarification? Is that to say whether it's in writing or to actually provide written communications between the parties on one item of a confidential discussion?

MS. RUBIN: Well, I'm looking for if it was in writing, I'd like to see it.

MR. MacDOUGALL: Well, I have to strongly object to that, Mr. Chair.

THE CHAIR: So, Mr. MacDougall, in terms of how far we can go, it's clear there appears to be some sort of dispute over exactly what the Settlement

Agreement is, in terms of how far the Board can go into that. What's your understanding of the law on that particular point?

MR. MacDOUGALL: For the Settlement Agreement, Mr. Chair, my understanding of the law is that it is a contractual arrangement and that it has to be interpreted with the law, and that it has to be looked at in its plain meaning in the whole circumstances of the agreement, and that for Parol or additional evidence to the agreement can only be used if they're, in certain discrete situations, an ambiguity on the wording, and I think there's a few others, which in our final argument, we will argue do not apply to this situation. But absent an exclusion to allow evidence outside of the agreement, the agreement is to be interpreted in accordance with the principles set out in **Sattva**, which would not bring these items in.

But secondly, if some of them are brought in, when does one start bringing in others from

other parties? And to be honest, we saw stuff in other people's written record that we think is simply their subjective comments on the agreement. We stayed away from doing any of that because we didn't think it was appropriate.

THE CHAIR: Okay. But in terms of the request for the document that Ms. Rubin has made, not suggesting there's any privilege or anything that would restrict the Board from asking for that request be made as an undertaking. It's the issue relating to how far you can go into settlement discussions and Parol evidence relating to the interpretation of the agreement.

MR. MacDOUGALL: That's my concern, Mr. Chair. I don't recall whether in those discussions everybody said everything was privileged. I guess it wouldn't have been privileged, per se, but clearly the parties were all under the view that these discussions were confidential.

MEMBER MELANSON: Are you suggesting

that there is no ambiguity whatsoever in the Settlement Agreement?

MR. MacDOUGALL: We will argue that there's not ambiguity with the specific clause. Other parties may argue there's some level of ambiguity, and I guess it would be open to them as to what they could then ask to be brought in. But my concern is that the questions we're getting into go into the confidential discussions. They enter into that area, and it's very hard. Even the fact that these questions are being proposed, I know, has concerned my client, Port Hawkesbury Paper, as to what one can or cannot discuss in settlement negotiations, because we certainly did not expect that the actual negotiations that were meant to be in confidence would be become part of the record in this proceeding. That, I guess, is open to the Board, but it then becomes a difficult position as to what does get in, what doesn't get in. Where's the cut off?

The material being asked for was part

of communications being carried out for the purpose of settlement purposes, confidentially.

(SHORT PAUSE)

THE CHAIR: So I think it's clear, at this point at any rate, that there's at least an intention to argue whether the provision was ambiguous or is subject to multiple interpretations. So on that basis, I think the Board will allow the request for the undertaking, both for the confirmation of whether the communication was made in writing and the document itself, if it was.

MR. MacDOUGALL: Thank you, Mr. Chair.

THE CHAIR: So, Mr. Lock, are you able to provide that by way of an undertaking?

MR. LOCK: We will take that as undertaking, and with two parts.

THE CHAIR: And that'll be U-18.

UNDERTAKING U-18 - To provide the written communications, if any, in which PHP

expressed dissatisfaction with the costing determinants that are embedded in the Cost-of-Service Study for GRA settlement purposes

BY MS. RUBIN:

Q. All right, Mr. Lock, I think these questions go to you. I want to understand more about the operations of the mill and operating modes.

I understand that an operating mode -- or maybe you can just walk me through what an operating mode or an OM is at the mill and, and why PHP's operations are structured around a fixed number of those modes rather than some continuously variable load level.

A. (Lock) Sure, I'd be pleased to. Just give me one second to bring up by my reference.

So ---

Q. And just for reference, I'm looking at your evidence Exhibit N-3 on page -- sorry; I

had page 4, but I don't really think that that's grounded there.

Just walk me through the operating mode.

A. (Lock) Sure. So as you noted in your question, Port Hawkesbury's load is not a continuous ramp of like it would be with a turndown of a generator, for example. Even though we've been considered a negative generator, our load use is characterized best as blocky. So following that, we did work with the utility when we first started the ELIADC to -- and the System Operator to block it into operating modes that we would characterize in terms of their load level.

So starting from the bottom we had an OM-1, which is -- thank you, John. OM-1, which was -- is known as our base, which is really just keeping the lights on or would be the same as the firm load. So that's in the range of 0 to 7 megawatts of -- so, and that is the ECC call because that could be interrupted down to zero.

It could be being held with some of that.

So the first block 0 to 7 megawatts, and we're really talking about, as we've known, you know, in and around 8 megawatts.

The next OM is OM-2, and that is 8 megawatts to 20 megawatts, but typically at a level of about 12 megawatts. So that's the lights are on, no production is happening, and auxiliary equipment like water pumps that would serve us and Nova Scotia Power in terms of water -- demineralized water would be running.

And then when we add the paper machine, if there was enough pulp in tanks, then we could add paper machine load of another few megawatts, about 20 megawatts to get up to the range of 35 to 45 megs.

Then ---

Q. Sorry. Sorry. OM-2 was 8 to 20?

A. (Lock) Eight (8) to 20, but average 12.

Q. Right. And then OM-3 is around

-- or is what?

A. (Lock) Twenty-one (21) to 45 is what we say is that broad range. But the blockiness, what it does is when we start up the paper machine there's no halfway; it's the full paper machine or not. So that takes it up to about 40 megs. And that can only be sustained until pulp -- bleached pulp is no longer available. So we have to start up the bleach plant, which is the next OM range, which takes us up to 65 megawatts on average. So just for range purposes, because there is ramping in the hour, so we are provided, like any other generator, a period of you can't go there immediately. Pretty close to it when you're coming down, but when you're starting up, it's -- there is some ramp that can happen. So that's 65 megawatts as Om ---

Q. Can I ask which exhibit? Are you looking at an exhibit number?

A. (Lock) No, this is -- we -- what I'm referring to is our exchanges between Nova Scotia

Power and ourselves we have as part of the operating procedure. It's a -- just a characterization. You just asked me to characterize it and I'm just ---

Q. Yeah, okay. Can you just tell us on which of those the biomass plant can operate under? Is that OM-1?

A. (Lock) All of them. So the biomass plant is the -- that's included in the base.

Q. In the base load.

A. (Lock) Yeah.

Q. Okay. Sorry; we were up to OM-4, which takes you up to 65 megawatts and you said some ramp time. And at that point, I guess you would have some paper machine load, some -- the bleach plant and ---

A. (Lock) Correct.

Q. --- then something else?

A. (Lock) No. So that -- to go to the next step, and that is creating unbleached pulp. We have to add a main line, which is one of three. We have

three different main lines.

So the first and smallest main line would be added and then create OM-5, which is really what we call Line 1 of unbleached, the bleach plant paper machine and that base load stacking to create in and around 100, 105 megawatts. Then -- sorry.

Q. And what's the range that's for OM-5?

A. (Lock) The range for OM-5 effectively is between 91 and 105, 106. It depends on the refining parameter. So if we -- you know, even actually change seasonally a little bit with different wood fibre, but...

Q. Okay, sorry, I'm a little confused here because I thought OM-4 took you up to 65, but what's the range, then, ---

A. (Lock) Yeah.

Q. --- for OM-4?

A. (Lock) OM-4 really is 46 to --

you could call it 70, but we don't fill in all the gaps. Like I said, it's very blocky. There's no ---

Q. Right.

A. (Lock) But 65 is the average of OM-4 with a range somewhere in -- like I said, it's really 60 to 65. It's very, very consistent there, 65.

Q. Okay. And then so what happens in that gap between 70 and the range of 91 that starts at OM-5?

A. (Lock) Nothing -- nothing turns there. It's a next step up that we add additional motors to do more pulping. So there's -- I mean, it's pretty instantaneous. When we start feeding chips to that, it starts up after a warm-up curve of about an hour, which is about .9 of a megawatt to idle those refiners. Then when we go into production mode, we pick up about 50 megawatts, so, boom, it adds on top of the 65.

Q. Okay. And then we go from OM-4, 46 to 70 range to OM-5, with a range of...?

A. (Lock) Call it 95 to 105.

Q. Okay. And the typical is what is there an average when you plug that in, or it could be anyone?

A. (Lock) A hundred and three (103).

Q. Yeah, okay.

A. (Lock) It's -- yeah, it's very -- it's stable within that range of 100 to 105. And then the next is switching out that pulping line with a larger pulping line. So that wouldn't involve shutting down Line 1 and starting up what we call Line 3, and it's a slightly higher load, so it jumps up to 115. So it's effectively swapping one out, unbleached pulping for the other. And you go from the 105 up to 115. So it's not a ramp. It's a move from one to the other, which is coordinated, yeah. And then -- so that would be OM-6. OM -- you okay?

Q. Oh yeah. Sorry. You saw the light go on.

A. (Lock) Yeah.

Q. Is there a range for OM-6?

A. (Lock) All of this is there's a little bit of range, depending on how much refining we have to do in the refining zone. So again there's swings of, you know, two and a half, three megs, around that average.

Q. Okay. And I'm not talking about what happens in fact; I'm talking about what is the permissible range in that OM.

A. (Lock) Permissible range? I don't believe that there's any permissions. It was -- it was to give guidance and work with the ECC in terms of what they could expect when the marketing group or Plexus or Jenops would have selected that -- that operating range. So it's not a -- there's no hard bounds on those OMs. It's to come up with a load range within those that typically is a pretty tight range.

Q. Okay. I'm going to -- there is an exhibit in the records, but it's confidential. And it

was the response to the SBA IR-1(i)(d). And if you can recall it, it's a table and it shows the blocks and the different ranges. And if you can't recall it, then we'll go to it in confidential. Or maybe it's not confidential since we've been discussing it all here.

A. (Lock) I think we're -- with an excerpt from it, happy to go to it and have it -- discuss it if it's a particular hour. Again, this is hourly resolution data that included the OM run level and commentary on it that with all years.

Q. Okay.

A. What year were you...?

Q. Well, let's just carry on and then I'll go back to that exhibit. We were up to OM-6 where you switched out line 1. You start up line 3, where it jumps from 105 to about 115 megawatts.

A. (Lock) Correct.

Q. Is that right?

A. (Lock) Yeah.

Q. Okay. Then what happens?

A. (Lock) Then the next OM that are currently active is OM-7, and that takes would be everything on; line 1, line 3, bleach plant, paper machine, and the base load. And that goes up to about 160 to 170 megawatts. Again, slight variations around it.

And I should mention that in the hourly resolution there could be many times we're getting dispatched intra-hour. So there are some of the numbers, the averaging would be -- that show something outside of that is a ramping period basically. You know, at the bottom of the hour, if we changed from 160 megawatts and we were asked to come down. Sitting here last Tuesday, we got a call to go from OM-7 down and drop 90 megawatts. And we dropped two units and provided 90 megawatts of relief in a -- in 20 minutes. So it's happening within the hour. So the average would not be exactly alignable to each of these OM modes, just to be clear. But happy to -- happy to try to explain that better.

Q. Have we hit the top of the OM modes currently?

A. (Lock) Correct, yes, OM-7.

Q. Okay. And when did it switch from nine operating modes to seven?

A. (Lock) January 1st, 2026.

Q. So what changed between the nine OM structure and the current seven OM structure, other than went from nine to seven?

A. (Lock) Yeah, yeah. The obvious.

Q. What drove the change, I'll say?

A. (Lock) Yeah. So as our regular discussions with Nova Scotia Power, and this is the operator and we were reflecting on the amount of time in each one of those operating modes and there was very few hours in OM-8 at all, which was -- OM-8 had been using line 2 as the unbleached line and then all the rest of the services. So it kind of came out in the middle. And it is slightly less energetic than line 1 and quite a bit

less energetic demanding than line 3. At OM-9, then, had represented running all three main lines; the bleach plant, the paper machine and the base. And what -- through the discussions with the utility, the modelling that drives their scheduling was selecting very few hours at OM-9 or OM-8. And for -- to improve reliability line 2 it was decided that it would be -- better serve the system and us if it was used as a backup for line -- for lines 1 or 3 improving the reliability of being able to take a significant amount of load. So gave the -- gave Plexus an ability to utilize that and the result to be more reliable. Because starting these lines, as I alluded to earlier, is not always easy. Just like starting up a generation plant, that doesn't always go according to plan. So having that in reserve, gave us another tool to ensure greater reliability and adherence to the operating modes.

Q. So in terms of your production, what does it mean that line 2 is engaged mainly as a

backup line?

A. (Lock) What it means is that the quantity of pulp produced by each of those three main lines, 1, 2, and 3, is different in terms of the tons. So to get the same amount of pulp, each one takes a different amount of time to get to a -- the same level of pulp-making. So the fastest or most productive line is line 3, followed by line 1 and then line 2. So that's -- what it would mean is to get the same amount of pulp you'd have to run in an OM that included line 2 for a longer period of time than you would if you were to use line 3.

So for example, in practical terms, what we see often done like pumped hydro storage is that if there overnight, particularly during, you know, peaky seasons and there's only six -- four to six hours of available power in a -- overnight, the model would choose and ask us to go to the highest production as to fill the silo. So it's quite a sophisticated model that Nova Scotia Power uses, whereby they're monitoring the pulp in

storage, and it's being used very much like -- identical to a pumped hydro model. They're using that extension of the port ops to do that.

So it's selecting when over the next number, as we've heard earlier from the schedules, is trying to optimize that pulp production using a combination of now two lines, historically three lines, but being called very, very few times line 2 is better utilized, in terms of ensuring that when the call comes that we're able to pick up the load to take either the wind that may be spilled or take advantage of not having the units back down below minimum -- critical minimum.

Q. Who proposed the reduction from nine operating modes to seven?

A. (Lock) John says it's us.

Q. And you said it will improve compliance. I think that's what you said.

A. (Lock) Yeah. Really, what -- you have some redundancy. I don't want to say compliance. I

think the better word, you know, if I may, is redundancy. So by having that line at the ready provide some backup in case when the first time you go to hit either line 1 or line 3, it does not go for some reason, which could be many, many, you have that ability to pick up load to satisfy the load shaping in a more reliable way.

Q. Okay. And is this what drives the expectation of benefits under the ADC and the improved outcome as compared to the load-shaping benefits under ELIADC?

A. (Lock) No, it doesn't drive anything. That's just the load shape of the OM-9 -- or OM-9 or OM7, it was not changed for that reason. If that's -- maybe I'm not understanding the question.

Q. Well, I think you said that reducing it from nine to seven to 7 will improve PHP's compliance with dispatch request or ability to respond to dispatch request.

A. (Lock) Yeah. Having a -- having

a backup line that's bringing -- that's ready to come across the line, we feel could help what is already a very reliable service compared to, you know, the whole utility space. We have very high uptimes, as evidenced by the ADC coding. I think it's 10, 15 percent of the time that we're not following the schedule because of PHP issues, failure to load being one of them.

Q. Now the peak load, the amount of load from PHP that's been available for dispatch has been reduced over time since the ELIADC has been in effect; correct?

A. (Lock) The peak load for modelling purposes has been reduced to simplify the model output, but those lines remain available. We have even been asked to run all three lines in some periods since that -- that change. So it's -- really was to be able to have the scheduling model that's done by Nova Scotia Power simplified and more straightforward with OM with seven OMs instead of nine. But we have -- we actually have peaked

higher than the 160 and 70 on some occasions, when asked.

A. (Esaiw) What you may be asking is our peak load over time has come down. And that's just because we become more efficient with some of our lines and our -- and we use less energy for the ton of paper we're making. And so our -- from well over 200 megawatts, we've improved our operations to shave off our absolute peak loads.

Q. Right. And that's what I was looking at the numbers, when from 2019 to 2023, it was 225 megawatts from '23 to '25, it was 205, and now it's at 160.

A. (Esaiw) Correct, yes.

Q. And that is as a result of improving the efficiency of your processes?

A. (Esaiw) The first two moves, the 225 to 205. The next step down, 205 to the 170 is a result of the -- changing the OMs, not an efficiency change.

Q. Okay. My notes say 160 and I was looking at the N-16 SBA IR-1, Attachment 1(a)(c), and you just said 170. What's ---

A. (Lock) One sixty (160), yeah, to be clear.

Q. One sixty (160)?

A. (Lock) Yeah. I mean, again, there's some range around the -- around the refining, but 160, yeah.

Q. Okay. And would you -- is it fair to say that with two fewer OMs available now than before and with two of PHP's three TMPs cycling rather than three, that NSP has fewer load points to choose from when deciding how much to dispatch PHP up or down?

A. (Lock) Yes. Technically yes. Two that their model would be choosing from a reduction of two.

Q. Now, the operating procedures -- and we have some drafts in there -- including the

operating mode characteristic schedule, those were initially developed by PHP in consultation with NSPI?

A. (Lock) That was a joint effort originally and the ELIADC, your -- or the ELID; which one?

Q. Well, I think it started with the ELIADC ---

A. (Lock) Yeah, right.

Q. --- and it's since been revised. There's a red line in here.

A. (Lock) Yeah. The -- for -- yeah.

Q. Okay.

A. (Lock) It still needs more revision, of course; as it's red lined, there's some additional things.

Q. Okay. And I was going to ask you that. Are you satisfied with what's been drafted, what's in the evidence now?

MS. RUBIN: And maybe we can just pull it up. It's Exhibit N-6, which is NSPI response to IG IR-

12, Attachment 1, and PDF 13 -- I think it's 1391 of 1474.

MR. NORWOOD: Thirteen ninety-one (1391)?

MS. RUBIN: Thirteen ninety-one (1391); that's it. And you're on the second page, Mr. Norwood, but if you go back that's the actual -- it goes back, Attachment 1. Correct.

BY MS. RUBIN:

Q. So that's what we're talking about; those are the operating procedures. And there's a red line that revises it compared to the ELIADC?

A. (Lock) Yes.

Q. Okay. And does PHP have any objection to the current version of the operating procedures?

A. (Lock) If you scroll forward, there are a couple characterizations I think have been misleading from the prior ELIADC and -- say objection, but just needing further wording clarity on the -- on the

coding section. So if we just scroll ---

MS. RUBIN: Do you want to scroll down, please, Mr. Norwood?

MR. LOCK: I don't have it committed to -- keep going, please. I think it's the last page of this. Keep going.

BY MS. RUBIN:

Q. Are you talking about the cause codes?

A. (Lock) Yes.

Q. Okay.

MR. LOCK: Mr. Norwood, yeah.

MS. RUBIN: And that's -- keep going. I think it's the next -- two pages more, there's an appendix.

MR. LOCK: Right there.

MS. RUBIN: There we go.

MR. LOCK: Oh. There you go, Mr. Norwood. Perfect. If you can just enlarge that?

BY MS. RUBIN:

Q. Appendix 1 and it's PDF -- I cannot read that.

A. (Lock) Yeah. So Appendix 1, the cause coding needs some better description. They've been an item of question through the reporting of the previous tariff, and I think could continue to benefit from some further wording improvements.

Q. Okay.

A. But that's it.

Q. Do you have any views how those should change to better reflect the -- what's occurring?

A. (Lock) Well, number one, because of the construct that the utility has put forward of comparing, as it was characterized, apples to apples in terms of a levelized load run compared to the dispatched load that the cause codes become unnecessary. And our -- as written really only focus on the one side of PHP-initiated requests. But the -- as has been seen in the

previous tariff, many times we're being asked to dispatch by ECC off schedule to what the marketing schedule would be. So that's within the current hour or the hours surrounding the actual hour. ECC has control and they would be asking us to deviate from schedule. So that, in these three, is not captured. It talks about PHP failure, PHP-initiated request level, to which NS Power or NRS System Operator agrees to. Really typically happens the other way; the System Operator asks us to assume a load level or an OM, and we agree.

Q. So you think that these are -- that PFL cause code 1, PNA cause code 2, and PDN cause code 3 are not -- do you agree, first, with how these three cause codes are defined, but you're saying you need more?

A. (Lock) No, I think that they're not -- cause code 1, just to be specific, that one, as it's written, is fine and clear in the situations that occur. So if Port Hawkesbury is asked again to pick up

load to OM-7 and we are not able to do that, it's a failure to load, and that would be captured in cause code 1.

What I'm saying is I don't think any cost codes are required whereby the current form that was put forward and which we agree with, with Nova Scotia Power's -- the compensation for that, that these codes become irrelevant as to who asked for what. It's a change that is captured after the end of the year, in terms of a levelized load versus the actual load following that would have occurred. And that could have occurred from Port Hawkesbury, and in this case, failure to meet the dispatch. But it's only impacting Port Hawkesbury and nobody else, so they're really not as required anymore.

Q. Okay.

A. (Lock) And number two, just to round that out, if I may, that needs -- if it was to be in place, the more regular is that the System Operator is asking for a load new dispatch level to occur, which is

not what the schedule had said. And we agree in the vast majority of cases, and in some others, we don't, if we have to get a -- as we've said many times, to get a special paper order out or production -- meet production requests.

Q. So that sounds like something completely different from cause code 2, because that ---

A. (Lock) Correct.

Q. --- originated -- originates with a PHP request.

A. (Lock) Correct.

Q. You're talking about an ECC originated request?

A. (Lock) Yeah.

Q. Okay. So in terms of the cause code 2 as it's written there, do you agree with that description as a cause code, whether or not you agree it's required?

A. (Lock) Yes. There are those

cases that that that would capture what I'm saying. And sorry, but you, I think, alluded to it, an additional cause coding. If it is determined that these cause codes are required would need to include a Nova Scotia Power-initiated request for new dispatch level.

Q. Okay. And do you know NSPI's views about this?

A. (Lock) No. Since we submitted this document, we have not talked to Nova Scotia Power about it.

Q. Okay. Okay. And then PBN is the PHP decision to vary from dispatch?

A. (Lock) Yes. And that that one would not be one, like 2, that the System Operator agreed to. So this would be purposefully running off schedule, but it's -- yeah, again.

Q. Okay. And I understand your -- I think I understand your statement that these aren't required. It that because the financial accounting is

independent of the reasons for dispatch compliance or non-compliance?

A. (Lock) Yes, that's a good way to characterize it.

Q. Okay. And last week Nova Scotia Power said that cause code reporting will continue for informational purposes. You recall that evidence?

A. (Lock) I do.

Q. And do you accept that some form of cause code reporting is still informative to distinguish dispatch-driven variances from PHP's own operational choices?

A. (Lock) I think that some description of why the schedule was varied from whether it's PHP initiated or System Operator. There's really a triangle, as Concentric and others have focused on, between the marketing group of Nova Scotia Power and the Nova Scotia Power System operator, even more so today as the Independent System Operator takes hold. And, you

know, that could be useful, but not necessary in this new construct where it's non-consequential. But it's tracking of as, as I think the record has shown, from the ELIADC, Port Hawkesbury's, you know what I -- what I think is very solid responses to maintaining schedule and only varying over the years -- the last two years, for sure -- in the range of 10 to 12 percent of the time in choosing those, a decision of drop dispatch failure or decision to vary. So a very small amount of time compared to in the utility space.

Q. Okay. So I think you said it could be useful, but it's not necessary. And the necessary was because of the structure of the ELID, because the financial ---

A. (Lock) Correct.

Q. --- calculation is independent of reasons?

A. (Lock) Correct.

Q. So unlike the ELIADC, you aren't

charged for failing to follow dispatch. It's a foregone benefit you could have achieved had you followed dispatch?

A. (Lock) Yeah. In the contemplated manner of a rider for demand response that compares a true comparison, apples to apples, of a levelized load compared to a modulated load, as determined by an optimal schedule, this level of tracking is not required.

Q. And going back to my question was that, in practical terms, if PHP deviates from a dispatch instruction for its own operational or production reasons, what it loses is the DR economic benefit it would have otherwise realized; it's not a separate penalty. Is that a fair characterization?

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

Q. I'm still going to dig into the operating procedures and scheduling, and so I think that's still you, Mr. Lock.

A. (Lock) Between the two of us. So that in a particular hour or just in general?

Q. Oh, I'm going to get there.

A. (Lock) Okay. That's great. I've been there through ---

Q. I just want to understand.

A. (Lock) I've been there through many nights of ups and downs.

Q. Okay. And maybe we'll start on PDF page 1392, these draft operating procedures.

A. (Lock) Sorry; I can't quite see. Are we at that 1392 maybe? That's the appendix one of...?

Q. I don't think so.

A. (Lock) Okay. Which...?

Q. Thirteen ninety-two (1392). Right, okay. And that's Attachment 1, page 3 of 8.

So as I understand -- oh, actually, before we get there, when I asked you if you had any objection to what was drafted, you took me to the appendix and the cause codes. Is there anything else?

A. (Lock) I would say we haven't had

a chance to go back and review what we've submitted so far, but it's likely there might be some amendments to this.

Q. Okay. All right. Can you confirm that under these operating procedures -- and I appreciate this is still in draft, but what's proposed is that NSPI forecasts monthly demand schedules based on PHP's demand forecast, which PHP provides to Nova Scotia Power quarterly or by exception.

A. (Lock) Yes.

Q. Yes.

A. (Lock) Yes.

Q. And then PHP also, on its own, unilaterally, it sets the timing of its own capital shutdowns, giving NSPI a minimum of one month's notice?

A. (Lock) Yes.

A. (Esaiw) If I may help clarify that, the discussion of annual shuts has been an active discussion. We work with the utility on their shut period

as well. So we're -- we are back and forth to come up with a reasonable time. But the technical catchall here is at least one month in advance, but that information we would be sharing and discussing well in advance. Actually, that starts when we submit currently to the AAR process, the annual adjusted rates. We would identify the amount of days that we expect down in each of the months of the following year. And at that time, we do try to pencil in as best -- because ourselves, like the utility, are bringing experts from around the world, at least until last week when the border stopped them. But the -- to work on things that those six day -- five, six day shut.

Q. And PHP also gives NSPI, it sets the timing of its own regular maintenance shutdown; correct? And it gives NSP seven days notice, except when urgent repairs are required?

A. (Lock) Yes, that would be a good way to characterize it.

Q. So the starting input for this

whole demand schedule sequence is PHP' own forecast and PHP's own planned outage timing, rather than something that NSPI generates independently?

A. (Lock) Correct. We start that process with our own annual forecast.

A. (Esaiw) And then there is back and forth, in particular with the timing of that shut period. But the profile of paper orders informs the load. And we look at our forward -- forward sales, as well as historical background. So yeah, we start from there.

Q. Okay. So from that starting point, can you walk me through, from PHP's perspective operationally, how the monthly demand schedule, Seven-Day Demand Schedule and then the Intra-Day Demand Schedule relate to one another?

A. (Lock) I can start, and John can correct me if I'm wrong.

So after the annual, which is by the months, then we regularly meet every Thursday to review.

And on five days a week, there is a day-ahead schedule that that's submitted by the day-ahead marketing person, and it's for seven days. So what that does is for every one of the hours for the next seven days provides us an outlook of the OMs that are expected OMs and load level.

Then throughout each day and all seven days, the day -- the real-time marketing person responsible provides us a number of schedules throughout the day. For example, in the last today, I think there's -- we're up to number four of those schedules. So in a regular day, John, it's -- we been targeting one every four hours?

A. (Esaiw) Between three and four hours we've asked NSP for updated schedules.

A. (Lock) So that's how it rolls the annual monthly. And then we do review on a weekly basis just with the team marketing the, you know, weather forecast, load forecast and everything for the next number of weeks. If there's any major items on their horizon or

our horizon that would help inform our readiness and their readiness with respect to providing generation and us being able to -- in best place to be able to take service at where the schedule is showing us. So if they're expecting a whole series of high-wind events, those are things that we would discuss and work with them, in terms of our storage levels together. So collectively we have enough storage to make sure there's no wind spill, maybe a day from today instead of the next couple of hours. So it's highly iterative and interactive as it cascades down from annual, monthly or quarterly, monthly, daily and the seven-day rolling.

Q. And then how are all these communications done?

A. (Lock) But for when we had the cyber incident, they have been provided from the marketing team via emails to our team, and then phone communications if there's any questions around it or actions. So then in actual, within the hour, current hour, as it outlines

here, ECC has any changes to that schedule, that's done by phone communication, direct line, like any other generator with -- with directly with the System Operator. We have a direct line in our control room. So they would call up, like I said, in the instances, like, yeah, sitting here last week and instantly see a call come through. We -- yeah, we have some tools that we share through Teams to inform John and I and others so that we're prepared to follow that. But written through emails, regular emails for the day ahead, which is the seven day and the real time, which is -- happens a number of times during each day, and then phone calls to adjust.

Q. So that that Seven-Day Demand Schedule, that's an hourly demand profile, right?

A. (Lock) Correct.

Q. Okay. And PHP's demands is optimized within that schedule as part of NSPI's day-ahead planning process, right?

A. (Lock) Correct. It's informed by

their runs of their model.

Q. Okay. And then the -- and then the daily, the Intra-Day Demand Schedule, what time does that land on your door?

A. (Lock) Not a particular time, but if there's been a system change that the marketer is aware of, maybe a Tie restriction comes in or a unit is derated or another one of the units, or wind is falling faster than it than done, they would reinitiate that and send us a new one. If that wasn't done, there -- ECC is always the ones that have their finger on the pulse, in terms of intra-day, intra -- even intra-hour, if there's something missed on the Tie or a Maritime Link drops out or -- yeah, so...

Q. Okay. So the Seven-Day Demand Schedule, which is the hourly profile, that governs unless there is a change required, in which case they issue an Intra-Day Demand Schedule and there can be more than one. In fact, you actually want it every four hours. Is that

right?

A. (Esaiw) We've asked for the frequency to be somewhere in that range because of our silo levels, because our silo level data gets transferred to Nova Scotia Power. And so they input the silo levels into their modelling, and that helps us manage our silo levels and then helps them manage our dispatch. So if there's nothing on the system going on, we've asked for at least three to four hours, just to manage our silo levels in their systems.

Q. And are they receptive to that?

A. (Esaiw) Yes.

Q. Okay.

MS. RUBIN: Can I just get you to scroll down, Mr. Norwood to item number 5? I think it's on PDF, page 1393. Yes.

BY MS. RUBIN:

Q. This says:

If, during the Current Hour, Hour 1 and/or

> Hour 2, system conditions change unexpectedly such that they have a material impact (positive or negative) on system costs, NSPO will contact PHP with the schedule change (an increase or reduction in demand) provided such changes fall within: the agreed Operating Mode Characteristics Schedule, the final communicated PHP shutdowns, and the Operating Procedure.

What are -- what -- can you explain what those "provided by's" mean?

A. (Lock) Just to give us a second?

"Provided by"; not sure exactly on that. "Provided by" but just in you reading it out, it just -- the Nova Scotia Power System Operator does contact PHP with a schedule change. But that's not a written schedule change. Those are in the form of a -- if that's what you're looking for, in the form of a verbal communication over the phone lines.

Q. Okay. Are there any restrictions on these? It says will contact with a schedule change provided such changes fall within the agreed operating mode, characteristics, schedule, et cetera. I don't

understand that, "provided such changes"; are there restrictions on the NSPO request schedule change?

A. (Lock) No, the Energy Control Centre, NSPO -- sorry; I'm having trouble with the acronyms. But they, of course, are the ones that are also in control of a call for interruption. So our tariff and this dispatch tariff are completely separate.

So number one, what this is referring to in item 5 is that they wouldn't be able to ask for half of a production line, for example. What that's trying to characterize is that -- that following the general OM buckets, that they would speak to it in those terms so that their expected load drop or pick-up would be instantly transferable for our operators in terms of understanding what they're looking for.

So a lot of times through discussions, we've even talked about operating areas and not just OM. So they would call and ask us to drop to house load; they would ask us to take down line 3, knowing exactly what

level of load relief they get when they ask for that.

So that's what it's -- that it's not like, "Please dial back or ramp down to something," you know, 10 percent or 5 percent less. It's that it's in those same chunks, which is completely separate from their role and responsibility with respect to priority interruptible or interruptibility; that still remains every hour, every day.

Q. Sure. And I understand that's a different mechanism. I'm focusing on this Dispatchable Tariff operating procedure and just trying to understand the limits of changes that can be requested on dispatch for schedule changes.

A. (Esaiw) So I think -- I mean, if you take that section in its entirety it's meant to address situations where we will no longer be receiving those emails from the Nova Scotia Power marketing desk inside the one to two hours, or the System Operator then takes control of our load as it sees fit. And so the

System Operator has to take into account our operating mode characteristics, the Oms; what communication if any, we've given them as far as any shutdowns, so they're aware of that, and then the actual operating procedure. And so it should follow those. Otherwise we're expected to follow the original dispatch schedule.

Q. So when NSPI or the System Operator issues a dispatch instruction, does it specify a target operating mode or a target megawatt level, or what?

A. (Lock) It provides it in -- in a grid in both OM and a megawatt, which is just an average. And that's changed over time, as we've discussed earlier, in terms of efficiencies or changes to the -- each of the lines. But it's in terms of megawatt by operating, in the columns, it's operating mode. And then there's put in there in terms of a general megawatt. So we're not controlling by megawatts; we're controlling unit processes, which come up with a megawatt level.

Q. So is that the purpose for the

ranges? So for example, NSPI will say, "Go to OM-2 8 megawatts," and if you are at -- and that range is 8 to 20, so if you're within 20, are you considered compliant with that direction?

A. (Lock) There is ramping and ramping up and ramping down. But within that hour that is the range. But when we go down to OM-2 with all of the pulping, all of the paper machine and bleaching offline, we get to, after some time and cooling -- you know, pumps coming down and whatnot down to that average load level. So there's a period it's -- of coming down, tailing down.

Q. Okay. Let's use OM-3, then, as an example, which you said was a range of 21 to 45. If NSP says, "OM-3, I want you 22 megawatts," and you're at 40 megawatts, does that -- are you considered to be compliant because you're within that OM range?

A. (Lock) Yeah. So our systems would record the average of the load for the hour that we're in, and then it has those OM bounds built into it.

And so if we're outside of those bounds for the average of that hour, it'll flag it, yes, as not being in compliance with that OM for that hour.

Q. Okay. And things are recorded in five-minute increments, are they?

A. (Lock) An hourly average.

Q. But there's also a recording of every five minutes?

A. (Lock) Right. So the commentary for inbounds or out of bounds is on an hourly resolution, but all the detailed conversations are, you know, whether it came at 15 minutes after the hour and we are -- we have our load levels from the mill meters, is a sub-minute. So we're seeing load very, very fine resolution. So -- and it's an average up for the hour that's retained, if you will, for the history of where we are.

Q. Okay. So I think what I was trying to understand, because I was looking at your hourly data and cause codes and I could see requests for certain

megawatt level and you weren't there, but there was no cause code, but you might have fallen within an OM range. And that was the purpose of my question is, as long as you're within that OM range, you're still compliant, and there was no cause code tracked under the ELIADC?

A. (Lock) There was an OM range, and then there's also, as part of the procedure that we've worked out with the Nova Scotia Power System Operator, is ramp time. So each of those movements between the various OMs do have some different ramp-ups and down times associated with them, and that is what we put in place back at the beginning of the ELIADC procedure. So we detailed it with the System Operator in particular because of the various -- and each one of them are slightly different, so there is some variation.

So what you would have seen is a case that fell within the agreed to ramp range or within the range of the OMs. Because as you, I think, get from our description, the ranges are not -- don't butt one another

perfectly. What they do is really speak to the average in there, and then time to get there. It's a factor of the resolution of the data that you're seeing.

Q. And I think where we see these operating modes; we see the nine operating modes, we see the seven operating modes, and we see the ramp rates, they're found in SBA IR-1(a)(c), Attachment 2. And I'm going to ask yourself and my friend if we can actually look at this even though it's filed confidentially? But given that we've been discussing all of these, I don't know if that's a problem or not. And maybe you can take a moment to look at it yourself and decide if that's a problem.

A. (Lock) Sure. If you give us a reference of where it is, I'll take a look at it, but I think it should be fine.

Q. It's -- sorry -- N 16, which is the response to SBA IR-1(a)(c), Attachment 2. And it's a -- it's a spreadsheet.

A. (Lock) Just let us open up that spreadsheet. I think we have it.

(SHORT PAUSE)

MR. LOCK: So just for clarity, the spreadsheet, just to make sure we're on the same one, covers the year. It has individual tabs running from 2020 until 2025 for every hour?

BY MS. RUBIN:

Q. No.

A. (Lock) No?

Q. Sorry. It's Attachment 2, and there are two tabs. One says, "OM mode to end of 2025" and the other says, "OM mode beginning January 1, 2026."

A. (Lock) I don't have a copy up here of that.

MS. RUBIN: Could I approach the witness, just to show?

MR. LOCK: That would be great. If you have a hard copy, I'll take a quick look at it, or I

can come to you.

BY MS. RUBIN:

Q. I don't. I'll come.

MR. MacDUFF: Watch the cord, Ms. Rubin.

(SHORT PAUSE)

MR. MacDUFF: Port Hawkesbury Paper is fine to share the confidential version with this group.

THE CHAIR: Okay, it's going to take Mr. Norwood a few minutes to pull that up. So that was Exhibit N-16, attachment 2 to IR-1. And again it's an Excel spreadsheet, IR-1(a)(c), Attachment 2.

(SHORT PAUSE)

THE CHAIR: Is that the correct document, Ms. Rubin?

Just let her check before you share it, Mr. Norwood.

Thank you.

BY MS. RUBIN:

Q. Okay. Mr. Lock, you may have been able to abbreviate some questions earlier if we'd had this up. And there -- this document shows two tabs, "OM mode to the end of 2025," and that's as we discussed.

MS. RUBIN: Perhaps, Mr. Norwood, we could turn to that tab.

BY MS. RUBIN:

Q. That shows the nine different operating modes. And then the next tab is the operating modes beginning January 1, 2026, which shows the seven? Yes?

A. (Lock) Sorry, I didn't know you were -- yes. Yes, correct.

Q. Okay.

A. Oms, yeah, up to the end of 2025, the full range of OM-9, and then the recently OM-7, the seven Oms, and then the grid explains it, as I was trying to answer directly in terms of the equipment configuration driving the various load levels and then ramps associated

with each of those moves between the various operating modes. So it's all really straightforward, I know.

Q. Okay. Across the top in the green rows, i's got "Operating Mode," I understand; it's got "Demand Level," I understand. What does, "Mode Priority" mean?

A. (Lock) That Mode Priority as we understand it really reflects Nova Scotia Power's modelling in terms of that they're able to input some weighting, in terms of the gen ops model runs, whereby the running in each of the modes would be preferred or not preferred, in terms of the ability to provide some running level.

Q. I'm sorry; I didn't understand that answer.

A. (Lock) So it's really, I guess, the -- put another way would be the proportion of expected time in the various operating ranges. So for example, OM-1, we're trying to make paper, so it's a very -- it's not

priority number one, it's down the list in terms of if -- that's not a operating mode that would sustain our business. Does that help ---

Q. Yeah.

A. (Lock) --- what they represent?

Q. Yeah, that helps.

A. (Lock) Whereas operating mode number five allows us to make paper from bleached pulp and unbleached pulp in a range from, say, 90 megs to 105.

Q. Okay. So if I look at that in these mode priorities, from PHP's perspective, you would ideally be within OM-5 and -6 in a range of 91 to 120 megawatts?

A. (Lock) Yeah. That is a mode that we're making available paper in a continuous way. I mean, recognizing that not every month or every week that we could be in that because we don't -- wouldn't have the orders to sustain constant running of an OM-5. So it's really just generally to recognize that that's a more, you

know, priority or a preferred than the other alternatives.

Q. Okay. And this document was produced by PHP in response to the SBA. Is this a PHP document or an NSPI-originated document?

A. (Lock) It would have originated back in its original form, the OM mode to end of 2025 through discussions and workshops with the System Operator, the ECC at the time. So it was a jointly created such to parameterize the models. It's been updated and worked around and it's provided every -- every time that Port Hawkesbury sends a note of some sort of disruption to that stack. So every time we send what we call a discrete line, I think may be seen in one of the other operating procedures, whereby if we have one unit operation that's not available we send with to Nova Scotia Power just to help clarify what is out. But it's a live -- you know, it's a document that's been in place and continues to be in place with modifications since the original ELIADC, and it was a joint work but underneath

our pen. "John Dobson," you'll see in the notes that you've expanded or that have been expanded here, was the Energy Manager at the time.

Q. Okay. And if you look to the memo to the end of 2025 in the mode priority there, up at the top, there's a section in grey and -- which is the old 2019 to June 2023. Then June 2023 to present, and present takes us to the end of 2025. It looks like there's a change in mode priorities in those times. Why? Why is that?

A. (Lock) The mode, the change, we did significant amount of energy conservation work on line 3. So line 3 had been underneath OM-6 there and Mode Priority 4 prior to Jan 1st, 2026. And that was in a period that we had three refiner motors as part of that line that used a total of three-line refining and about 60 megawatts of load. And what we had done throughout '24 and '25 was reconfigure that line to operate with two motors, reducing significantly the amount of energy for

the same amount of pulp. So it's energetically been now made to be on very similar terms as line 1 in terms of its pulp production efficiency, at the same time of reducing the overall load. So it's really our work on energy conservation, as we had said that we would continue to do. And we taken out one whole 24-megawatt motor of that and added a little more incremental load on the primary and secondary in that position and therefore changing the -- both the overall -- the demand level and also the priority set.

So for us, currently OM-5 or OM-6 are largely interchangeable. There's only a few tons per hour in the difference, and both are making acceptable quality pulp at a very good specific energy set point.

Q. Okay. And these priority modes, these are -- it looks like while in -- presently and in the timeframe 2023 to the end of 2025, it covered two different Oms, and in 2019 to June 2023, it covered only one OM, it looks like the range is roughly a priority

demand level between 90 or 96, up to 120 megawatts. Am I reading that right, when you look at the Priority 1 mode?

A. (Lock) You are, yeah. So in an operating period and not in a down day, those are -- those are the operating modes. Recognizing, though, that, say in January or February, we'd only be operating, you know, 50 percent of the day. So the majority of the days we would be down at OM-2. So -- but when we are running, making paper and that stable operating, the priority would be those OMs in the range of the 90 to 105 or 90 to 115, in and around there. One twenty (120) as it stated here; sorry. Just to be specific, yeah. I'm too tied up with watching the hour by hour.

Q. You saw me reaching.

A. (Lock) Yeah.

Q. Now, when we were talking about those ECC or NSPI intra-hour request, the dispatch changes, and the discussion was based on -- within the limits of, I think it was, PHP’s operational -- the

language had to do -- is it within PH -- is it within the operating mode and within these transition times as shown in this schedule?

A. (Lock) Correct. What we're trying to get across is the equipment configuration. Each one of those is an on or off; the paper machine is either on or off. There is a little bit of ramping that then gets modified, as you say, within the characteristics down below in rows -- what looks like -- I can't quite see it, but in the coloured; the pink and then yellow and green. Those are the transitions.

Q. So just to make sure I'm reading this correctly, if you're at OM-3 and you're asked to go to OM-2, what block and row do I look at to see the -- to see how long it takes the transition time?

A. (Lock) So you would start on the column of OM-3, read down to -- I apologize, I can't see but to the OM-2 row that is there, and in this version it has a three included in there, which is three hours.

Q. Okay. So it takes three hours to drop to OM-2, but it's 1.5 hours to go to OM-4 and it would only be .3 hours to go to OM-5?

A. (Lock) That's correct.

Q. Okay.

A. (Lock) That's how you'd read it.

A. (Esaiw) I would add to that, though, this is data that gets used for NSP to input into their dispatch model. If we're taking instruction from System Operator and we need to drop load, these don't necessarily apply anymore.

Q. What does?

A. (Esaiw) The transition times you're talking about here. If we need -- if the System Operator calls and asks us to drop load, ---

Q. Yes.

A. (Esaiw) --- that's completely outside of what NSP is modelling for our dispatchers we get emailed to us.

Q. I understood that, and we were talking about Item 5 in the operating protocols that said if the system conditions change under -- unexpectedly, the System Operator will contact with schedule changes so long as within agree -- within the agreed operating mode characteristics and schedule, et cetera, et cetera. And I was trying to understand that, and I was looking to this sheet to see if that helps inform that "So long as" language.

A. (Lock) Yeah. I think what John's trying to explain is the, you know, shutting down of the bleach plant happens in large part in a very large chunk. And then there's a small tail getting that -- that represents the three hours. So we may have achieved 95 percent of the load relief in the first five minutes, but that there is that three hour that would be still, we would be in compliance if we got there, either from a change to the schedule provided by the marketing group or an inter-hour change. So we don't -- you know, the record

shows that we don't wait till the end of three hours to bring it down. We make the change, but there is a tailing-off of rotating equipment that we can't stop solidly, but on very, you know, needed basis, which would come underneath of an interruption where we would cut free. The machinery still would be running, but we would cut free from the grid, and, you know, incur the damages that that may occur by stuff running.

Q. So I guess my question was with that, in the hourly kind of intra-hour, are there limits on what they can ask you to do?

A. (Lock) They -- what we're -- what that's trying to get across is their instruction should be bounded by the equipment configuration. I wouldn't call it a limitation, but you know, what they could expect to realize by asking to change from one mode to the other. Or like I said, often the operator-to-operator discussion includes discussion of, "Well, we want you to go from OM-5 down to host load or AMA OM-2. So you know, if that was

possible, they -- we would -- we would do it right away. There's no limitations on that.

Limitation going up, John points out in terms of, you know, turning these on, getting them warmed up, steamed up. So there is on the ramping side, which you'll see there is longer. So the upper right-hand side from that black diagonal line, you see some longer ramp times than you do on the triangle that is sort of to the left and below the black line.

So dropping load is achieved more quickly than picking up load because of that warmup, thermal expansion, those type of things that have to happen, similar again to a generator or any other industrial -- large industrial process that there's (inaudible due to mumbling), yeah.

Q. And just for completeness, what is that box down at the bottom left where it says, "L3, pulp silo; TMP, bleached pulp silo"? What do I take from that?

A. (Lock) Yeah. So like was mentioned earlier ---

MS. RUBIN: Mr. Norwood, perhaps you could scroll down so we could bring that up on the screen?

MR. LOCK: Just scroll down.

MS. RUBIN: Scroll down a little bit.

MR. LOCK: Yeah. Right there where it has the...

So as ---

MS. RUBIN: Sorry. And in the 2026 tab, please.

BY MS. RUBIN:

Q. All right. Thank you.

A. (Lock) Yeah. So what that is representing is the build of energy storage in terms of percent in each of the operating modes. So each equipment configuration has different pulp storage results. So what this is showing, for example, in OM-3, just starting with the column that's labelled, "L3 pulp silo," in OM-3

there's no build, nor is there a reduction in that storage level. In OM-4, for example, there's on average, a 3.4 percent decline in the storage level over an hour. So these are hourly changes that result from the various operating modes. And it's sort of bracketed in line 20 there by the level.

So after 90 percent, then that's really the maximum anyone would want to have in the silo. So there is some ability to run a little bit over it, but at 100 percent, it overflows and makes -- some equipment -- a lot of damage. And below 30 percent, because it's a conical bottom; this large silo has a conical bottom, below 30 percent the rate of decline increases. So that that rate is constant -- of build or decline is constant between 30 percent in the silo and 90 percent in the silo. So that's what the level 30 to 90 designates.

And as I said, this is representing the ebb and flow, if you will, of energy storage. So exactly what this -- the earlier rate and the new rate

continue to look at is being able to take energy at an advantageous time for the system and Port Hawkesbury, maybe when there's an abundance of wind or low load conditions, to build up that working inventory, and vice versa for the utility in their modelling is to draw it down at a rate such that there's capacity left in the reservoir.

So as I said, they've used actually the same modelling tools as one would have if we had a pumped hydro storage system. So that's present in many, many other jurisdictions, where there is a pumped hydro that you fill a lake and then draw it down afterwards. This is the very same; we can use that put more pulp in than we're using in the paper machine during periods, and then likewise run off of reserves. And there are two of these silos, a line 3 pulp silo, which is unbleached, and the TMP bleached pulp silo is after the bleach plant. So there's two storages; 6,000 cubic metres in the first case, 4,000 cubic metres in the second case. We're

talking in the range of 16 to 20 hours in the first silo, and in the second silo it's usually closer to a maximum of eight hours.

Q. That's very informative. Is any of this reflected in the operating procedures as a boundary or a constraint, in relation to those operating procedures?

A. (Lock) Not in the operating procedures written out here in the Word document, to my knowledge, John. But they are modelling parameters that the various modellers over this period have used in the training or bounding of the model. So they are bounds such that, for example, we couldn't run an extended period in either OM-7 because we would fill all of the available storage and have nowhere to put it and therefore not be able to take any load and be off schedule. So the model has to work within those ranges. And likewise, you know, we couldn't run on zero in the silo either.

So it -- the model and that schedule

is a result of Plexus working within the equipment configurations characterized by OM numbers and bounded by these drops and increase fills that I should -- getting way deep, but the TMP bleached pulp silo is just a variable that is tracked; it's not bound. It does not bind -- influence the model output. It's only the line 3 pulp silo that's used. It was -- there was an attempt to do both, but it became highly complex that the model couldn't optimize both. So it currently uses a tool that was not available from 2020 to 2004, I think, and wasn't available until the hydro -- pumped hydro storage add-on was purchased.

Q. Okay. Thank you.

I just want to go back and follow up on a question because I think either I misheard you or you may have misstated, and it has to do with the transition time. And, yeah, this is the tab I want to look at, the OM Mode, beginning January 1, 2026.

And on the far left, it says, "From

current operating mode..."

MS. RUBIN: Mr. Norwood, if you could scroll over far left, right, "From".

BY MS. RUBIN:

Q. So I had read this to say you start with the mode in the grey on the left, and then you look to the right to see where you're going to. So for example, if I am from OM-3 and I'm going to Om-2, it's two hours. But if I am from OM-3 and I am going to OM-4, and you carry across that row, it's 1.5 hours.

A. (Lock) Correct. I misstated, I took you from column to row, it -- you are correct that it's row to column.

Q. Okay, that's ---

A. (Lock) Apologize for the confusion.

Q. No problem.

MS. RUBIN: Mr. Chair, I'm about to turn to a new topic. Is this a good time to break?

THE CHAIR: It is. Thank you very much, Ms. Rubin, appreciate that. So it's 25 to 12:00 -- sorry; to 1:00 right now. We'll come back at 25 to 2:00.

--- Upon recessing at 1:35 p.m.

--- Upon resuming

BEVAN LOCK, Resumed:

JOHN ESAIW, Resumed:

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

Ms. Rubin?

MS. RUBIN: Thank you.

CROSS-EXAMINATION BY MS. RUBIN, (Cont'd)

Q. I want to switch topics and talk about the -- PHP's interruption history.

MS. RUBIN: And if we could turn -- start with, Mr. Norwood, N-16, which is PHP's response to SBA IR-1, which is the PDF, and its PDF page 2, which is the question that sets up the answer.

MR. NORWOOD: PDF page 2?

MS. RUBIN: Yes.

BY MS. RUBIN:

Q. Okay. Now, in that IR, the request was for schedules, the reasons for initiating ADC, interruptible rider, operational emergencies or other reasons, duration, and the interval load data. And the response was to provide those various Excel spreadsheets that we've looked at. And in the PDF non-confidential portion of the response there, it says in the first lines, 23, "Note that the..." So it refers to Confidential Attachment 1 "for NS Power's rolling dispatch of operating modes for each hours and PHP' load levels." And then it says:

> Note that the PHP load shown in the Attachment is inclusive of NS Power station service power for the Port Hawkesbury Biomass Plant of approximately 4 [megawatts].

So my question was, we were just looking at those -- that spreadsheet with the pretty colours of red, yellow, green, does -- and the operating

modes. Are those ranges inclusive of the Port Hawkesbury Biomass Station service requirements of 4 megawatts?

A. (Lock) Yes.

Q. Okay. Now, at line 29, it says:

> PHP notes there is only one instance of being interrupted by the NSPSO over the past 6 years and all others were as a result of ADC and/or PHP operational decisions. This event occurred January 9, 2021. PHP was asked to go to zero [megawatts] by the NSPSO due to a system emergency, which it did. No other details were provided to PHP on the cause of the event. Twenty minutes after the call by NSPSO, PHP received a call from NSPSO...it could begin restoring load.

Did you go to zero?

A. (Lock) I just want to confirm that. One second.

Q. Sorry; this doesn't need to be a memory test, because I think we can actually pull up the data, which is that attachment. And I've confirmed with my friend. Mr. MacDougall. that we can show these -- this hourly data. It's -- yeah.

A. (Lock) Let's go right to the hour

and then we can explain zero and the data that's shown there, whether that's inclusive, or not, inclusive of biomass.

Q. Right.

MS. RUBIN: So if we could pull up N-16(c)(i), Confidential Attachment 1, which is response to SBA IR-1(a)(c), and go to the Tab 2021 and just maybe highlight on the screen rows, say, 2010 to 2016. There we go.

BY MS. RUBIN:

Q. And just to orient us, Column A that's the operating mode like we've talked about. It says OM-2?

It's -- sorry; I didn't hear an answer.

A. (Lock) Sorry. Just looking at the data comparing it to what I have in front of me.

So yes, that's corresponding to the different operating modes.

Q. Okay. And that is OM- 2 that was in effect as of 2021, which would have been ---

A. Eight.

Q. --- OM-2, which was 8 to 20.

A. Twenty (20), yeah.

Q. Right, okay. So at -- and then Column B shows the hour and the date; the date and the hour. And is that the ending hour?

A. (Lock) Hour ending.

Q. Hour ending. Column -- Column N is the load after dispatch?

A. (Esaiw) That's the intra-hour calculated load.

Q. Intra-hour calculated load. What does that mean?

A. (Esaiw) It's the average load over the course of the hour.

Q. Okay. And -- okay.

A. (Lock) So just so we're clear on

the numbers rose 214, 215 that have a four in Column N?

Q. Yes.

A. (Lock) Yeah, would be the metered load inclusive of the Port Hawkesbury Biomass. So essentially zero load from PHP.

Q. Right. That was my question. So at the time when these directions were issued, PHP was at 13, which I think has been called house load?

A. (Lock) House load or OM-2, yeah. So the schedule, as you pointed out in Column A, from the marketing team would have been house load or OM-2, which is a range of 8 to 20. We were sitting at 13, and then in that time period that's highlighted there was an interruption call, which is not coded here because it's a separate, individual rider.

So we're two different things. One is what this shows is the ebb and flow hourly of dispatch instructions from the marketing team, known as the rolling real-time schedule, that's provided emails. What it does

not capture here in comments or the coding is that the interruptible rider was enacted, as we answered here in the IR response 1, that in that period we were interrupted. And then the resulting load is captured here because this is just the meter numbers that for a couple hours there we were at a load level of -- Port Hawkesbury effective load at zero for hour ending 19 and 20, respectively.

Q. Okay. And you said what it doesn't capture is that it is IR rider inactive, but there's a cause code listed of NDN, which I understand is the System Operator initiated dispatch down?

A. (Lock) No, it's not System Operator. It could be any of Nova Scotia Power desks. So it could be the marketing desk or most often the System Operator underneath the ADC portion of the rate. And that's what the coding is capturing, separate and apart from a call to interruption, coming from the same System Operator desk but completely separate.

Q. Yeah, and that's what I don't see because the records that have been produced show a demand response initiated with a dispatch ramp-down request, coded as such. And the coding is done by Port Hawkesbury Paper. I think it was you, Mr. Esaiw, at the time?

A. (Esaiw)That year I was not employed by Port Hawkesbury Paper.

Q. In 2021?

A. (Esaiw) No.

Q. Oh, I understood you were there from the ELIADC outside;, no?

A. (Esaiw) No. I'm sorry; I started there in 2023.

Q. Okay. Thank you. So the coding is done by PHP, and it's coded as a Nova Scotia Power System Operator initiated ramp-down. And so what do you have to tell me, to demonstrate, that this was a request for interruption versus a System Operator request for ramp-down as it's coded here?

A. (Lock) So that would be two different places. I mean, this is coding is the movement underneath the dispatchable portion of the rider, which we capture hour by hour. But also we do -- our operators keep track of all changes in their plant and under their area. So there would have been a comment in a log, as well as the System Operator's log, we would expect, because they're -- Nova Scotia Power is actually the one required to document those requests, but our coding and more detailed in a separate software in -- on Teams, actually; we have it as a request for interruption. And this -- what this was provided to show was the regular ADC up and down, either by schedule or by exception, not including -- not including the interruption calls.

Q. So are you saying that the load was something other than 13, and went down to nine and then four under some request for interruption?

A. (Lock) No, we're saying that the load in hours 15, 16, 17, and actually before that were

13, which is in the range between 8 and 20, OM-2, and then we got an additional call first to drop additional load, which we did. And that that still was requiring further, more immediate reaction. So the System Operator interrupted us, along probably with others within the -- within their interruptible class of company, so ---

Q. Sorry. Did they interrupt you as in they turned a switch, or you responded to a request for interruption?

A. (Lock) They -- we would have responded to a request for interruption. And if we had not, they -- like those, the telemetry customers in the Industrial Group or others, they could have turned it off.

Q. Yeah.

A. (Lock) But in this case ---

Q. I was just wondering what happened in this case.

A. (Lock) In this case, Port Hawkesbury complied first with the dispatch requests down.

Q. And sorry; let's take this step by step. So it was at 13?

A. (Lock) Yeah.

Q. And it complied with the dispatch down to nine under, is that right?

A. (Lock) Right. But ---

Q. And then -- and then the nine to four? It says NDN as well; looks like a dispatch down request.

A. (Lock) M'hm.

Q. Is that not a dispatch down request?

A. (Lock) Yes, it is.

Q. And then it remained at four, and then it was directed and went back up again.

A. (Lock) Yeah.

Q. So what I'm missing is you're telling me that apart from these load changes that were System Operator-directed dispatch down, where's the

interruptible piece? Where's the interruptible piece?

A. (Lock) The interrupted piece is in the response -- in the text of the response of IR number 1 that we started with. This is -- includes every hour of the regular DR portion. So the interruptions are tracked by the System Operator according to their protocols of -- and what we have in a separate tracking comment of things is further information that provides additional colour on the phone exchanges that happened.

Q. Okay.

A. (Lock) So what you're seeing here is we continue to be hourly schedulable, and then answerable to the System Operator if there's changes. As it's been said, when things don't go as planned, we get requests either to pick up load, means coming on faster; drop load is dropping it -- or there's a tight system.

So what was happening on that day, from what I'm reading between the lines; it was a while ago, but was that the system continued to tighten and

tightened to a point that the -- they asked and formalized the separate rider in terms of interruption, which can happen any hour of any day.

Q. Understood. I'm not looking for hypotheticals. I want to drill specifically.

A. (Lock) No, I'm not giving you hypotheticals. I know from every hour what has happened with respect to ---

Q. I know, ---

A. (Lock) --- interruption.

Q. --- Mr. Lock, that they can at any time ---

A. (Lock) Yeah, okay.

Q. --- in theory call for it. But the primary means of controlling Port Hawkesbury Paper is through the Active Demand Control, as evidenced from the fact that over the last six years there's only been one call for interruption, you've said.

A. (Lock) I wouldn't say it's the

primary thing. There is the regular -- the regular rhythm of moving our load around is based on two, three things. The regularity is the real-time marketer provides the optimal schedule, moves around, and ECC does not interact. Then at another smaller subset of those hours, the System Operator, because of changing system conditions, either greater load, less load, unit failure, whatever, does an addition. As it says in those operating procedures, they'll call and ask us to act out of order of the schedule that came from marketing. And then separate and apart from the ADC portion or the demand control is the interruptibility rider that was part of the ELIADC and is also part of the ELID going forward, which supersedes everything. So they wouldn't have had to call in advance or anything. They could call out of the blue, put us on notice and then go through the procedure.

Q. Yeah, I understand how the interruption works, Mr. Lock. And when you just recited that whole process I noticed you did, in fact, say

interruptibility at the last. And you'd agree with me that in the six years that the ELIADC operated with this interruptibility provision, you only came up with one occasion on January 9, 2021 as a result of a system emergency where when that interruptibility provision was resorted to; correct?

A. (Lock) That's correct, actually.

Q. So what distinguishes a request for interruption versus a System Operator ramp-down request as recorded here?

A. (Lock) Sorry; can you rephrase that? Because one is a very formal, following the procedure laid out in the interruption, which happened, as you pointed out' one time in those six years. All the rest of the hours and moves that have been made up or down at the request of either the day-ahead marketing as part of a schedule that's sent to us, or those tweaks and changes as system conditions change, as -- you know, and many times it's been said has been value -- so if you look

back in the record that you have up, back to lines 170 or 180, what you see is that Port Hawkesbury has actually been off or very low load for the better part of two days leading up to the call of interruption.

So clearly what is happening is there's been value in having Port Hawkesbury's load reduced using the tools underneath the ADC. They were not sufficient enough in that one hour that's been mentioned, out of the six years that they felt they needed -- a System Operator made that choice, whether their operating reserve was exceeded, they invoked the separate interruption rider. So what rules the day is schedule, then cascading to the, you know, sort of inner hour control as it's laid out current hour, the next three hours of the System Operator, and a System Operator either is doing that or they have the big stick, which is interruption.

Q. Now, what records do you have to show the -- I guess it's a notice, then an alert, and then

the call for interruption?

A. (Lock) We would have, like I said, in our daily shift log, which is documenting everything from a pump turned on, turned off as one of the commentaries, the -- in the -- in that log, proprietary log, that we keep, you know, because it covers everything, in terms of various orders and whatnot, that would be documented there. And I trust, through what I understand, the Interruptible Tariff and rider is that Nova Scotia Power would also have record of those.

Q. Could I get you to produce the records that you have to document the calls for notification, the alert, the notification; like, the escalating alerts and then the time when you were requested to interrupt, and then the direction to restore under the interruptible rider where you said you have it documented?

A. (Lock) We can provide the shift log for that -- for that period to go back, because it's

not in a -- in a structured database to go and search that trigger, but knowing the events that have been identified here by going hour by hour by hour, we can provide a clip out of the log.

Q. Yeah. Whatever information you have to document to demonstrate that this was a request for interruption versus a ramp-down request as it's recorded here under -- in this spreadsheet.

A. (Lock) Yeah. But recognizing that this is -- we need to fill it out for every hour. And it's to document the ADC, move the control, not the interruption. So that they're not ---

Q. No, no, no. I'm not looking for the ADC control piece.

A. (Lock) Yeah, okay.

Q. I can see the ADC control piece here.

A. Yeah.

Q. What I'm looking for is the

records relating to the call for interruption.

A. (Lock) Yeah. The recorded line that Nova Scotia Power would have maybe the best to go, but to be helpful, happy to provide the log for that day where it would be included in the raw format that our operator would have typed it in.

Q. Yeah.

A. (Lock) Which are -- which are detailed here in -- at least in general, that there was -- PHP was asked to go to zero due to a system emergency, which it did. No other details were provided to PHP on the cause of the event. And I can show you the actual clip of a of the log which is in in a tool.

Q. Yeah. Now, under the interruption procedures, --

A. (Lock) Sorry; is that an undertaking? Did you want to have that as an undertaking, or are we going to go on?

Q. Sorry, I do. Thank you.

THE CHAIR: That will be Undertaking U-19.

UNDERTAKING U-19 - To provide all records in the care, custody, and control of PHP that demonstrates the requests under the interruption protocol, which would include the escalating alerts notification and the call for interruption and PHP's compliance

MR. LOCK: So for the hours surrounding January -- in January 9th, 2021?

BY MS. RUBIN:

Q. All records in the care, custody and control of PHP that demonstrates the requests under the interruption protocol, which would include the escalating alerts notification and the call for interruption and PHP's compliance. And then usually

there's a subsequent call that says, "Okay, interruption's over."

A. (Lock) Just to be clear, the compliance, is that not already provided here in the hourly megawatt level?

Q. Well, my difficulty is that this is showing a System Operator directed ramp-down coded as NDN.

A. (Lock) Yeah.

Q. But you're saying that I can't take that at face value that it is an NDN-coded DR ramp-down, and that instead there was a call for interruption. And so that's what I'm trying to understand.

A. (Lock) But there's no "instead"; it's on top of. So just to be clear, what the regular course of interaction is, that that would be the request underneath the ADC tools. And then if that still was not sufficient and there was a system emergency, there would be a call for interruption. And we're happy to provide

it. As you've described all records in the care and custody of Port Hawkesbury that details the phone exchanges. They -- I do suggest that Nova Scotia Power may be able to provide the recorded line if you need to verify that, but I'm happy to provide our version of it.

Q. Okay.

A. U-19?

Q. Yes.

And just to clarify, you said it is on top of this. So are you telling me that -- so you were at 13 in the hours preceding 5:00, and then by 6:00 you responded to a dispatch-down direction and went to nine. At seven you were down to four, and you stayed at four until the hour ending at 8:00 p.m. And then you were allowed to increase and you went up, according to the ramping requirements, and you went back up to your house load, I guess, by about 11:00 p.m.?

A. (Lock) Yeah. And then shortly after, like I was saying, you know, subject to breakdown,

we had a failure to load and get back to OM-5, because having taken an interruption and being ramped-down, we had some equipment, you know, challenges in terms of the ramp-up. So you see the whole day, you know, two days before it starts, trying to, you know, work and help the system and avoid interruption of other customers. And that's done through the ADC.

It almost skated through, and then they needed to pull that extra lever of calling for an interruption, which then there was a return to service as we talked about. And unfortunately, in returning back at our ending 24 to the OM-5 that had been asked for by the real-time desk, we weren't able to comply.

Q. Okay. Now, if this is an accurate report of the ADC control and the ramp-down request and response. What load -- how many megawatts was actually interrupted?

A. (Lock) We'd have to look at where we were in that -- that time because the interruption

could come within the hour. I can't answer you clearly, but it looks to me as if it was about 5 megawatts that effectively would have been shed.

Q. And what are you looking at to say about 5 megawatts?

A. (Lock) From 9 megawatts to 4.

Q. But this shows that as a coded under the DR as a direction to ramp down. So how do you count the same megawatts, both under a system-directed ramp-down and an interruption?

A. (Lock) So we don't have a cause code for interruption. The cause coding hourly tracking that's in here is to codify the ADC portion of the tariff. It is not as a record of calls for interruption.

Calls for interruption can happen separate and apart on any one of the 8670 hours out there. So we're -- and -- but it is shown the result on -- an hourly resolution is shown in Column N, which is the megawatt loading level on average for that hour.

So they're one on top of the other; they're two separate -- two very distinct and separate mechanisms.

Q. I understand they're two separate mechanisms. What I'm trying to understand is if you were at 13, and it looks like you were at 13 for a number of hours ---

A. (Lock) Yeah.

Q. --- earlier in the day, because clearly the System Operator was aware of the capacity constraint, so they had you down at OM-2. And you were operating at house load, 13, which is pretty much just the auxiliary, none of the thermal pulping. You were down to the auxiliary systems and the Port Hawkesbury Biomass Plant, right? That's about house load 13?

A. (Lock) That's right. And then ---

Q. And then in -- as constraints, system capacity tightened more, in hour 6 you were given a

direction to drop further.

A. (Lock) Yeah, which could have been OM-1, but this -- the coding in A is from the real-time desk.

Q. Yeah.

A. So what was -- what was in an email exchange, that doesn't change when the System Operator makes a request. So the schedule that you have here in A -- maybe this is helpful -- is the schedule that was dictated and exchanged in an email format as to the expected load level.

So in the hour that's under control of the separate part of Nova Scotia Power, the Nova Scotia Power System Operator, they have two tools they can continue to use one or both of the demand response requests, which they did clearly here. They asked to come down at hour ending 18; hour ending 19 they asked for more. And somewhere in there, which is not evident in this data, which is not data intended to show

interruption, but rather the compliance to the dispatch, then what -- you see the result, though, down to 4 megawatts, which is essentially the zero, which is further documented for the specific call that came in, in terms of the call to interruption, separate and apart and over and above this data, but for the load. And we can provide, like I said, the --it's called Plant Applications, is the tool that we use for coding all that stuff. And we can -- we can do a clip of that.

Q. Okay. So I guess we'll see when we see the records that you have in relation to this with U-19.

A. (Lock) But I'm not sure what you see more than what I've done, but in terms of that the call came in, it was an interruption call, and we dropped load further to comply with that call for interruption, just like any other interruptible customer would. And it would have been captured in commentary, separate and apart from this ADC tracking, which is a separate aspect of the

ELIADC Tariff. And going forward would be the same.

Q. In your operator's notes, does it actually have the times? Does it record the times of these calls?

A. (Lock) I'd have to refer back to that, but ones that I have personally been involved with, yes, we would mark down that the call came in at -- you know, a timestamp and that a call back. So it's -- you know, we cycle through five shifts of three people on a shift. So there's quite a few different individuals involved, and their notetaking ability is different from one another. So what's in on that hour, I'll have to have a look when we take that undertaking, but it should be -- should be fairly detailed, yeah.

Q. Okay. Thank you.

(SHORT PAUSE)

MS. RUBIN: We're just trying to reorganize here. Okay.

Mr. Norwood, would you turn to Exhibit

N-13, which is Port Hawkesbury Paper's response to the Industrial Group IR-10. And the question is on PDF page 12, and then maybe we can look at the answer on 13.

BY MS. RUBIN:

Q. Okay. So these are -- question (c) says:

> Confirm whether PHP was, in fact, dispatched or instructed to curtail load by NSPI/NSPSO during each of the 2020-'23 winter 3CP hours identified in NSPI's ELID evidence.

And then it requests the information about PHP's metered demand immediately before and after. And the answer on page 13, it provided that in each of the six winter coincident peak hours identified in NSPI's evidence for 2022 and 2023, PHP had been dispatched into a specific operating mode, for example, OM-2 or OM-5 in advance of the peak hour, and remained in that mode throughout the peak. Is that -- is that correct? That's my understanding?

A. (Lock) Yeah, just reading them through. But yeah, as it stated.

Q. Okay. So just setting that up.

MS. RUBIN: And then if we go to Exhibit N-6, which is the response to IG IRs, and it's PDF 199 to 219, NSPI's responses to the IG IRs. Yeah, okay.

BY MS. RUBIN:

Q. And this shows NSPI's monthly sales generation and demand analysis by class; correct?

Have you seen this before, Mr. Lock?

A. (Lock) Yes, I have. This is for January '27?

Q. Yeah. This is the forecast for '27. And I understand, although in line 8 where it says, "ELI 2 part RTP" that is just -- I'm going to ---

A. (Lock) Yeah. That was identified by Nova Scotia Power in their panel as that is just a historical coding.

Q. That's historical coding.

A. (Lock) Yeah.

Q. Right.

A. (Lock) Yeah.

Q. That's intended to represent PHP under the ELID above-the-line tariff, right? And so then if you go to PDF page 212, and if you go page by page, it'll show January, February, March, and then I'm going to take you to 212, which puts them all together, every month. Okay?

And so this is the monthly class system coincident demand with line losses; correct? And just to compare it with, it's without line losses at page 213, which is the following page. You can see that the delta with and without, and you can see that -- yeah. So you can see that PHP in Column 9 is shown at 65 for January, February, and I guess the December at 65, and then 135 for the remaining months.

A. (Lock) Yeah. No, that's what Nova Scotia has -- Nova Scotia Power has plugged in there for 2027.

Q. Right. And then -- and that 65, that came from the determinants provided by PHP?

A. (Lock) What -- why Nova Scotia Power put it in there, I can't say where the determinants came from. It was not by instruction of Port Hawkesbury for 965. As I said earlier, actually the most recent look at the 3CP, which this is intended to be, would be more like 28 megawatts, ---

Q. Okay.

A. (Lock) --- not 65. That was inserted by Nova Scotia Power based on, you know, subjective judgement of themselves or I don't -- I can't answer why that would have been. And they definitely have included that in the Application, but that's not our instruction.

Q. Sure, okay. Could we turn to PDF page 219? Okay. And just enlarge that a little bit, please, Mr. Norwood, my eyes aren't that great. Okay.

BY MS. RUBIN:

Q. And this shows both the class system coincident demand and non-coincident demand, right?

A. (Lock) Yes.

Q. And it's a forecast for the year ending December 31, 2027?

A. (Lock) That's what it says.

Q. Right. And for PHP it shows the system coincident demand peak in Column 8 at 67 -- or, sorry. The system coincident demand in Column 6 is 65, and that's consistent with NSP's Application.

A. (Lock) Correct.

Q. And that's the number that originated with PHP as the demand determinant in the DRs preceding the Settlement Agreement. It's consistent with that.

A. (Lock) We had, under 4-1, asked for a modelling parameter to be considered and for interest of 65, correct.

Q. Okay. Now the non-coincident

forecast demand for PHP is -- which is Column 4, is shown as 199,370 megawatts. You see that?

A. (Lock) I do see the number, yeah.

Q. And so my question is how do you reconcile that to the high demand of 160 and the top of the operating modes that we were discussing?

A. (Lock) I think that's a probably a question better suited for Nova Scotia Power. I mean, that's -- I don't know how or where that would have come from. I could -- I'm not about to guess that it was a historic OMs or something to that effect, I don't know, but that's certainly above the 160 megawatts that we were speaking about earlier in terms of the range of OMs.

Q. Now, you changed the operating OMs from nine to six in the top of the range. Was that after this forecast was put together?

A. (Lock) I don't know. Can we -- I don't know when this forecast was put together.

Q. It was preceding the GRA.

A. (Lock) Would have been after. Sorry; this would have been before the changes to the OM which came into effect Jan 1st, 2026.

Q. Right.

A. (Lock) Yeah.

Q. So this preceded the change in the OMs?

A. (Lock) Yes. So that could explain the non-coincident demand number at 199. But ---

Q. And when you look at what was in effect to the end of 2025, OM-9 ranged up to 205 megawatts; 17205?

A. (Lock) Correct.

Q. And the current OM, top of the OM leaderboard goes up to 160 megawatts?

A. (Lock) Correct.

Q. Okay. Now, I just wanted to pick up -- you said something about the 28-megawatt demand, and if we could go to -- I just want to -- I think this number

may be off and so I want to just drill down into that.

Now, in response to N-6 -- sorry; in N -- Exhibit N-6, which is the response to IG IR-30, and it's marked confidential, but it is now public; that was the agreement of my friends during the questioning of NSP. That was the updated PHP historical three coincident peak data for 2024/2025.

MS. RUBIN: If we could pull that up, please, Mr. Norwood. N-6, IG IR-30, and it's N-6, the confidential version. It's IR-30(c), and I'll just see if I can find the PDF page. It's PDF page 171 of 175.

Could you just scroll down a little bit so we've got that entire table? There we go.

BY MS. RUBIN:

Q. Okay. Now, this request asks for the updated PHP historical 3CPs for 2024 and 2025, and the response is provided in that Table A. And that data yields the average demand of 28 megawatts; correct?

A. (Lock) I'll take your word on it.

I didn't do the math, but yes.

Q. But isn't that the source of ---

A. (Lock) Correct. That's what I've been referencing, yeah, is this dataset. Yeah.

Q. And am I correct that all but one of those figures appeared to be dispatched down to, I'll call it the house load?

A. (Lock) Yes. Whether it was part of the schedule or whether it was a dispatch instruction, I'd have to go through and look at each one of those. But yeah, they would have come from one of -- one of either the Nova Scotia Power real-time marketing schedule or the hourly control in the current hour and the preceding couple hours.

Q. Okay. Now, the load for the January 19, 2024 peak is stated to be 95,890 kilowatt. See that?

A. (Lock) Yeah.

Q. And then when I compared that to

the hourly data that was provided by PHP in response to the SBA IRs, which is N-16(c)(i), Attachment 1 IR-1(a)(c).

MS. RUBIN: And perhaps I'll ask my friend if we can actually pull up that figure on that line item?

MR. MacDOUGALL: I'd have to see the Non-confidential.

(SHORT PAUSE)

MS. RUBIN: Yeah, it's the same spreadsheet that we looked at previously when we were looking at the hourly data in 2021. But this is in 2024, and it's row 454. Yeah, 454.

THE CHAIR: It was the 2024 tab you were looking for, Ms. Rubin?

MS. RUBIN: Twenty twenty-four (2024) tab, yes.

Sorry; offline while you scroll.

MR. LOCK: The data I'm looking at is 11.16 megawatts; is that what you're seeing?

BY MS. RUBIN:

Q. Yeah, that ---

A. (Lock) Just different than what is included in the IR response for that same hour.

Q. Right, and that was that was my question. So, yes, we can see a line 454, you're at OM-2, and down to 11.16.

A. (Lock) Yeah. We'd have to look at that data. Just looking at the string of megawatts in the hours before and after, don't see anything close to the 100-megawatt level. So obviously -- I shouldn't say obviously, but I would require a further checking of the pi data, the meter data for that hour, and we can take that as an undertaking.

Q. Okay. Do you think perhaps that this -- well, I guess you're not really sure which one may be incorrect.

A. (Lock) Yeah.

Q. Okay.

A. (Lock) I think I would suggest checking with the mill meters and the Nova Scotia Power billing data for the -- that hour. And then start from, the -- that dataset to determine. I'm not sure where Colin (inaudible due to mumbling) ---

Q. Okay.

A. (Lock) --- because that's who produced those others.

Q. Okay.

MS. RUBIN: Perhaps, Mr. Chair, if we could get an undertaking to confirm whether the -- what is the reported load for PHP at that peak.

THE CHAIR: January 19, 2024, hour 19; is that what we're looking at?

MS. RUBIN: The January 19, 2024 peak.

THE CHAIR: Okay. Undertaking U-20.

UNDERTAKING U-20 - To confirm what is the reported load for PHP on January 19, 2024, hour 19 peak

THE CHAIR: We can take that exhibit down now?

MS. RUBIN: Yes.

THE CHAIR: Okay.

MS. RUBIN: Thank you.

(SHORT PAUSE)

MS. RUBIN: Could we pull up, please, Exhibit N-12, which is PHP's response to the CA IR-4, which is at PDF page 7?

BY MS. RUBIN:

Q. And I'll just give you a moment to review that, Mr. Lock.

MR. LOCK: Mr. Norwood, can we scroll up a little bit on the response, please? That's fine. Thank you.

(SHORT PAUSE)

MR. LOCK: Yes. Familiar.

BY MS. RUBIN:

Q. Okay. So that question --

A. (Lock) I have a paper version if we want to continue?

THE CHAIR: Not sure our transcriber is online at the moment, so just hold for a second.

(SHORT PAUSE)

THE CHAIR: Apologies. I think we're good to go now. Sorry.

MS. RUBIN: The question is probably not worth all that much.

(LAUGHTER)

BY MS. RUBIN:

Q. Okay. Mr. Lock, in the response to IR, lines 38 and on it says:

> PHP is proposing a value of 0 [kilowatts] to be used for PHP's winter month system coincident demand for interruptible load since PHP' interruptible load is subject to dispatch by NS Power.
>
> If demand at the historical 3CP hours reflects NSPI's dispatch choices rather than PHP's own operating pattern exclusively, do you agree the same

reasoning applies whether the resulting allocator is 65 megawatts or 28 megawatts, or any other figure that's drawn from those same dispatch-determined hours?

A. (Lock) Sorry; can you say that again? Just sounded like there was a little bit too much packed in there.

Q. Okay. If the demand at the historical 3CP hour reflects NSPI's dispatch choices, and they do; correct?

A. (Lock) Yes.

Q. Do you agree that the same reasoning applies whether the resulting allocator is 65 megawatts, 28 megawatts, or any other figure that's drawn from the same dispatch-determined hours?

A. (Lock) So to break down the answer a little bit, you know, we are subject to Nova Scotia Power's dispatch. So where they place our load at the coincident peak, and number one, there's not perfect visibility on what are going to be the 3CPs. But given

that our load level is in the hands of Nova Scotia Power, the keys, then the resulting demand at the 3CP level in the most recent years and applicable years would be consistent with the 3CP cost causality approach. We -- however, we do also feel that there's a good argument to be made that there's -- where we're placed, without, you know, us being in control, should mean that the -- effectively it could be zero and should be zero.

As was mentioned earlier in Nova Scotia Power's panel, there are reasons why Port Hawkesbury's load may have been held at different load levels during coincident peak: The wind could have been blowing high as it, you know, may have been dictating choice to run Port Hawkesbury to pick up and not spill wind, for example, or some other reason. But for Port Hawkesbury the demand that we put on the system or that needs to be built for us, in terms of the approach for coincident peak, there's no extra capacity -- demand capacity being brought online or built for Port

Hawkesbury's load because we -- the utility has the ability to change our load down to zero.

Q. I'm going to just change topics now to the dispatchable rider. And can you confirm that the energy charge that NSP proposes to bill PHP under the ELID Tariff flows through the Fuel Adjustment Mechanism in the same as the energy charge for any other FAM customer?

A. (Lock) Yes, that's our understanding.

Q. And the dispatchable rider credit that's paid to PHP for shifting load, that's intended to be funded from savings generated for FAM customers as a whole; is that correct?

A. (Lock) Savings generated for all customers? Sorry; can you rephrase it, the question?

Q. The dispatchable rider credit, ---

A. Yes.

Q. --- that's intended to be funded

from the savings that have been generated, fuel cost savings generated for FAM customers as a whole?

A. (Lock) No. It would be from Port Hawkesbury's actions -- would flow from Port Hawkesbury's actions of optimizing for its purpose because it's comparing the flat load to a moderated-demand response.

Q. I'm not talking about how it's derived. I'm talking about the credit that's been paid, the dollars. The dollars that are paid to PHP for shifting the load, how is that being funded?

A. (Lock) By savings in the total energy because of Port Hawkesbury flexibility and willingness to offer up its service. So it's a -- it's a fee for service of providing a demand response that's flexible, effective, and has, you know, provided value.

Q. Sure. And how is that fee for service funded? Where does -- where do the dollars come from to fund that?

A. (Lock) It comes from the delta,

as Nova Scotia Power has put forward the delta between the levelized load and the actual moderated load, dispatch load.

Q. And what's the input to the levelized load? Those are the costs associated with the fuel, right?

A. Yeah. So it would be the -- at the end of the year, all the megawatts that would have been -- that would have been used, and the fuel used or -- because of the dispatch load versus what otherwise would have happened if Port Hawkesbury wasn't providing that service. So there's no other -- it's not coming from anywhere else but from Port Hawkesbury moving its load instead of maintaining a flat or levelized type of load. But for, you know, shutdown days that would come out of that.

Q. I think we're doing this between my questions and your answers.

A. (Lock) Sorry.

Q. No, that's on me for not being clear on my questions.

Nova Scotia Power maintains that other customers will be held harmless because the fuel costs savings, which are generated as a result of the dispatch of PHP's load, is paid to -- that savings offsets the credit that's paid to PHP and so there's ---

A. (Lock) Correct. It's a closed loop. So our actions resulting in a more optimal selection of energy during that, would be -- flow from that -- those -- that moderation of our load up or down, and also provide additional benefits, in terms of avoiding interruptions and other things for other customers. That's the other -- that's the other thing of real cost that is not put onto -- borne by other customers in this tariff application would have us continuing to provide significant load relief, load shifting to address, as Nova Scotia Power continues to say, when things don't go according to plan, which is a very large amount of load

compared even to the complete interruptible or the IG group together.

Q. Okay. Mr. Lock, I don't want to cut you off when you're giving an answer that's responsive to the question, but if you can give yes, no's, then we can hopefully get you out of here by the end of the day.

A. (Lock) Yes.

Q. Okay. Will PHP receive this DR credit in a single invoice item after year end, or how -- is it going to come monthly and then trued up, or how is that going to work out?

A. (Lock) We understand it will come as a lump sum after the year is over and NSP runs their calculations for the fuel cost savings.

Q. And there was some evidence that NSPI has a new methodology to quantify the value of ADC that was developed following the last FAM Audit. And do you recall that evidence?

A. (Lock) Yes.

Q. Okay. And NSP proposes to use this to calculate the dispatchable rider credit going forward. Is that your understanding?

A. (Lock) Yes.

Q. Has PHP reviewed and agreed to that methodology?

A. (Lock) Yes.

Q. Have you been given an opportunity to test it in this proceeding on data from here, or...?

A. (Lock) We've simply seen the results of some Plexus modelling that was put forward along with the Application that used that new methodology. That's -- we didn't use any other data to look at that.

Q. Sorry; when you said you saw it applied to the Application? Was it just -- was this -- when was this?

A. (Lock) I don't know exactly where it is, but they've showed that range of 7 to 11 and then

they said in reality it's probably more like 3.5 to 5.5. That's what we're basing our answer on.

Q. Oh, so to your understanding that 7-11 or in fact, it's 3.5 to 5.5, that was based on this new dispatchable -- the ADC control methodology?

A. (Lock) Our understanding is the 7 to 11 was the result of modelling runs that they had done following the simplified version, yes, of using the same forward curves as we talked about and the -- and modelled against a levelized load at -- fixed for this amount of energy for the full year, underneath the two different scenarios; a dispatch load versus a levelized load. With -- that all add up to the same megawatts at the end of the year.

Q. And why, to your understanding, is the realistic number about half that?

A. (Lock) I think that was Nova Scotia Power's, you know, view that it could be less than that. I think they alluded to, you know, allowing for

some cases that Port Hawkesbury didn't choose the optimal, or the inputs to the model may have not been optimized, as has been explained before. That these models are brutal optimizers, so I think they were just putting their practical experience on there. I think our experience to date and expectation's a little bit different than that, but we think there is a significant amount of value there to -- if we do behave in a fully dispatched, optimized way, that we have an opportunity to reduce our costs. Although that balance is difficult when we get down to the lower level, it's -- it would be more difficult to justify offering that service if it was a *de minimis* amount or...

Q. What's your view as a more realistic number?

A. (Lock) We think the lower range of what they provided should be achievable, given our track record of our operator's ability to move our load around in the responsive way that we've seen under the ELIADC.

Q. So 7 million?

A. (Lock) Yes.

Q. And is that influenced at all by the reduction in operating modes, which makes it more likely to be able to comply with dispatch requests?

A. (Lock) Not directly or materially, no. There was very, very few times in the previous tariff that we were in either of the OM-8 or -9, so we don't think it will have a big impact.

Q. Okay. I just want to get the timing straight. You said your understanding was this 7 to 8 million was a result of NSPI's New methodology. Is that right?

A. (Lock) Sorry; seven to...?

Q. Seven to 11.

A. (Lock) Eleven (11), yeah. Eleven (11), yes.

Q. Yes, sorry; 7-11 was as a result of NSPI's new methodology.

A. (Lock) Yes.

Q. Okay. In NSPI's reply evidence, and I'm not sure if we need to turn it up; I can just read it out so we can stop some shuffling, but it's N-38 at page 23, lines 15 to 19, says, "NS Power has developed a methodology to quantify...":

> As discussed during the Q2 2026 Fam Small Working Group...meeting, NS Power has developed a methodology to quantify the value of ADC to value load shifting isolated from changing prices. This was developed in accordance with Recommendation XV-3 from the 2022-2023 FAM Audit. This methodology will be subject to FAM [Small Working Group]review and subject to Board approval of the ELID Tariff...future FAM Audits.

Now, just a little confused of the timing because that Q2 FAM Small Working Group postdated the Application by some six months. So I'm wondering when you had the opportunity to review or agree to or test that new methodology.

A. (Lock) I can't recall the timing. I'd have to go back and look at the various inputs there,

but I can't recall off the top of my head.

Q. Okay. And are you satisfied with the new methodology?

A. (Lock) Yes.

Q. Okay. And I believe we have an undertaking to see that, so we'll get that in this proceeding.

A. (Lock) I guess. What undertaking was it, just so I could keep track?

Q. It was from NSPI.

A. Okay. Sure.

(SHORT PAUSE)

BY MS. RUBIN:

Q. A couple of short snappers here.

The ELID Tariff has a Power Factor Correction clause; correct?

A. (Lock) Yes.

Q. And same language as the ELIADC?

A. (Lock) Yes, a direct transfer

from the ELIADC. Didn't mention demand-only energy, yes.

Q. Okay. Has PHP's average power factor, in any billing period since 2020, fallen below the 90 percent lagging threshold specified in the draft ELID Tariff's Power Factor Correction clause?

A. (Lock) We only have evidence on our billing from it happened one week since we've been on ELIADC. We get billed weekly, so it did occur on one week.

Q. Do you know the circumstances of that?

A. (Lock) We happened to be down, in an outage at the time, and it resulted in this Power Factor Correction during that outage.

A. (Esaiw) Was it the annual outage?

A. (Lock) I think so, yeah.

Q. And does the change in the TMP production lines affect power factor performance? I guess my question is, do you have any reason to expect that your

power factor performance under ELID going forward would differ from historical under ELIADC?

A. (Lock) No. Thanks for the reframe.

Q. That was quick.

A. Yeah.

Q. Okay. A couple of questions on Goose Harbour.

Is that you, Mr. Esau?

A. (Esaiw) That would be Mr. Lock.

Q. Okay. Mr. Lock, the Goose Harbour Lake Wind Facility currently has a system impact study approval for 130.5 megawatts of installed capacity?

A. (Lock) Correct.

Q. And as of the time of the evidence, the second SIS Application for the remaining capacity up to 160 megawatts had not been approved; correct?

A. (Lock) Correct.

Q. Do you have any status update on this?

A. (Lock) Generally I can say that the required models, PS SE and PS CAD models, have been sought by the System Operator as they're reviewing it. That's still ongoing. No -- no update as to the timing that we'll hear the final. But I do know that it is moving and active with our turbine supplier, Nordex, yeah.

Q. Okay. Now, the wind energy that's purchased by PHP under the Goose Harbour arrangement is netted against PHP's load before the PHP customer baseline load and energy charge exposure are calculated; correct?

A. (Lock) Correct.

Q. And that's true for the loads used in the cost of service; correct?

A. (Lock) Yes.

Q. And in the FAM CBL, NSP uses the full load, inclusive of what is served by wind, 800

gigawatt hours? Like, would ---

A. (Lock) In the FAM, I think the currently it's 774 for the -- for the full load, inclusive of both energy provided underneath the -- from the wind arrangement and from Nova Scotia Power directly.

Q. Right. So any shaping of that 800 or 774, whatever, it's compensable services by PHP, even if the energy comes from Goose Harbour; correct?

A. (Lock) Correct. The movement of Port Hawkesbury's load in an hour is still at the full -- that full amount is still fully dispatchable by the utility like -- yeah, like it is today.

Q. And am I correct that any generation above the 130.5 megawatts from the Goose Harbour facility is intended to be curtailed until the second system impact study is approved?

A. (Lock) That's correct.

Q. And if the Goose Harbour output above the 130.5 is curtailed, how will that curtailed

output be treated under the PPA? Like, is it available to reduce PHP's net load or its energy charge during the curtailment period?

A. (Lock) No, because it relates to the interconnection. It's clipped. It's -- would not pass on to the grid, so there's no PPA or sales agreement megawatts corresponding to it until such a time that the second system impact study is finished and that site is cleared for full operation to the 168, which is about 3 or 4 percent more energy than currently estimated by P-90, yeah.

Q. Okay. And the Goose Harbour Wind that -- I'm going to call it a sleeved PPA; there's a purchase agreement and a sales agreement. It nets against PHP's metered load as an end of month or an end of year transaction?

A. (Lock) End of month.

Q. Look how quick we're getting on these. Okay. Looking at the banking mechanism itself, if

the Goose Harbour output in any given month exceeds Port Hawkesbury's consumption, it can be carried forward and applied against PHP's consumption in a later billing period; correct?

A. (Lock) The following month, yes.

Q. And sorry; you had said earlier that PHP was billed weekly under ELIADC. Will it be billed weekly under ELID or monthly?

A. (Lock) In our preliminary discussions with Nova Scotia Power, we expect it'll still be weekly billing.

Q. So you're billed weekly, but Goose Harbour can be carried forward and applied in a later month? Or is the billing period referable to your bills, so weekly?

A. (Lock) I don't know if we've exactly sorted that out. I would expect that on the first weekly bill of the new month, that any of that volume transition would be included in that next weekly bill.

Q. So any banked amounts could be carried forward for a week to week to week, and then trued up or carried forward into the next first week's month bill?

A. (Lock) First week's month's -- yeah, next month's bill. Yeah, that's correct.

Q. The first bill ---

A. (Lock) Of ---

Q. --- of the following month.

A. (Lock) Which is weekly. To the best of our understanding, yeah.

Q. And if the ELIADC Tariff isn't approved to PHP's satisfaction and the ELIADC expires by the end of this year, could PHP still receive the energy output from the Goose Harbour Wind Farm?

A. (Lock) Yes.

Q. Would it supply sufficient energy to meet the mills needs?

A. (Lock) No, it would not.

MS. RUBIN: Could I just take a moment to confer?

(SHORT PAUSE)

BY MS. RUBIN:

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

A. (Lock) Thank you.

A. (Esaiw) Thank you.

THE CHAIR: Ms. Power, you're up next, but I think we'll take our brief afternoon break. So it's five after 3:00 now. We'll come back a quarter after 3:00.

--- Upon recessing at 3:05 p.m.

--- Upon resuming

MS. POWER: Thanks, Mr. Chair. I don't have any questions.

THE CHAIR: Okay. Thank you.

Mr. Mahody, you're up.

(SHORT PAUSE)

MR. MAHODY: Thank you, Mr. Chair.

CROSS-EXAMINATION BY MR. MAHODY

Q. Good afternoon, gentlemen.

Mr. Lock, could I start just confirming an understanding? I don't think it's contentious, but your Opening Statement makes reference to becoming an above-the-line customer. Do you agree with me that an above-the-line rate is intended to recover, from each customer class, their appropriate share of system embedded costs?

A. (Lock) Yes, I agree with that statement.

Q. And those embedded costs are the fixed costs of the system. Do you agree with that?

A. (Lock) Yes.

Q. And those would include, for instance, depreciation and return on investment for rate-based assets.

A. (Lock) Yes.

Q. Could I turn next, Mr. Lock, to

the firm demand that PHP is asking the Board to approve as part of the ELAD Tariff; and that's specifically your request for the 8 megawatts? It is correct, first off, that that is the demand that you're seeking to have set as the firm demand for PHP?

A. (Lock) That is correct.

Q. And as you've testified to already today, the house load would be closer to the range of 12 megawatts and under production use the flow to the mill could be multiple times those numbers; correct?

A. (Lock) That's correct. Just one slight -- the 12 would represent the sum of both Nova Scotia power's power use for the biomass, as well as Port Hawkesbury's interruptible load of 8, yeah.

Q. Okay. And in relation to transmission studies and assumptions, I read in your evidence where PHP has said that it's not been privy to the assumptions Nova Scotia Power uses in its transmission planning studies. Is that correct?

A. (Lock) Correct.

Q. But nevertheless your expectation is that the transmission system would be able to serve PHP's maximum expected load; is that correct?

A. (Lock) Yes, similar to past rates and loads. Yes, the current rate or the max load going forward is lower than prior. And we continue to believe that the system would be able to handle that max load, yes.

Q. And Mr. Lock, do you see any issue with setting the billing determinant at the 8 megawatts, as you're asking to do, with the knowledge that the transmission system, the request of the -- of PHP is that that transmission system would deliver 160, 170, 180 megawatts?

A. (Lock) I guess my understanding of the use in the cost of service of 3CPs for the purpose of demand, the 8 megawatts would be the -- what the utility would have to have in place to serve that -- that

demand level.

Q. The generation it would need?

A. The generation, yeah.

Q. Yeah, okay. But then back to my question, then. Is there not a misalignment between your position that you'd use that 8 megawatts as your billing determinant for transmission, when the request is that significantly greater transmission assets would be required to deliver the 160 or 70 megawatts?

A. (Lock) We heard from the -- Mr. Stanford, I believe, that he said that when they're doing system planning, they don't plan for our high load on the transmission or generation side.

Q. Okay. Yes, I heard Mr. Sanford say that. But you also appreciate that the request that's being made is that the mill be supplied with a transmission system that can supply the 160 or 170 megawatts of load.

A. (Lock) Fully interruptible load,

yeah.

Q. And the impact of that interruptibility on the transmission assets, Mr. Esaiw, is what?

A. (Esaiw) I'm not sure I understand what the impact would be on the transmission system.

Q. Is there any.

A. (Esaiw) We're alleviating the system on the generation side.

Q. I appreciate that. I haven't asked that. I'm asking from the impact on the transmission. Is there an impact on the transmission system, from that perspective?

A. (Esaiw) I don't believe so, for fully Interruptible.

Q. I wanted to ask some questions about the reasons, other than Nova Scotia Power dispatch reasons, that would cause changes to PHP's load. And as I understand the evidence, PHP's electricity needs depend in

part on the -- on its paper order book. That's correct?

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

Q. And PHP's forecast for the following year can change because of order book changes?

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

Q. Okay. And you were discussing your operating modes with Ms. Rubin earlier. You can make changes between your operating modes in order to maximize efficiencies and make improvements at the mill more generally to improve your efficiencies. You've testified to that?

A. (Lock) Yes, we are continually driving toward energy conservation and -- whether it's in thermal or electrical aspects. So yeah, we continue to invest in studies and in improvements to reduce our electrical load or steam load, albeit for the same production level, yeah.

Q. And so, Mr. Lock, do you agree that PHP's actual load can change for reasons other than

Nova Scotia Power's dispatch schedule?

A. (Lock) In general, yes, but at a very different resolution. The dispatch schedule is an hourly for the most part, but for some sub-hourly that happens at the -- at the request of the System Operator. Whereas large-scale capital projects and improvement is a longer runway of change and is discussed, as you see evidence of changing and operating modes, through a discussion with Nova Scotia Power, that we're going to attempt to minimize our operating modes by changing the configuration of line 3, which changed slightly our megawatt levels for that line. But that's in a -- so I guess the simple answer is, yes, there are other things that that impact our load sort of year over year, as well as the order book that you asked about before.

Q. And how does the ELID Tariff, as you seek it to be modified, how does it reflect changes to load for based on Nova Scotia Power dispatch instructions or requests that it makes of you, its schedule that it

provides, versus any of those other changes to load?

A. (Lock) Can you slightly reframe that?

Q. So I'd understood from our exchange so far that changes to PHP's load could be the result of a schedule that Nova Scotia Power dispatch schedule the Nova Scotia Power provides. That'd be one main category of reason. But then there are other categories, other factors that would cause PHP to decrease its load, for instance. What -- how does the tariff in operation distinguish between those two so that you're isolating the dispatch-related load changes from the other load changes?

A. (Lock) Yeah. We think it would be captured in -- and the regular review of operating procedures that of any large-scale, you know, engineering changes or energy efficiencies, which would be on a much longer time-range scale. So it really would be handled through that discussion of the various OMs that we

reviewed earlier today. But the majority, certainly over the run of any one year, the driver remains the dispatch, the hourly dispatch, informed by the demand that we've provided in terms of an annual look-forward forecast. And of course, like any other -- any other user, you know, there would be impacts due to sales in the month, sales in a week, sales in a year. So there's some up and down and no true up on other rates or in other rate forms. And this would be the same, that we deal with it operationally.

Q. Can I turn to PHP's request that it receive 100 percent of the dispatchable rider value? And you had been asked about this a bit earlier, and I won't repeat it, but I did want to take you to Exhibit N-11. It's PHP's response to Bates White IRs, and it's IR-3.

MR. MAHODY: Mr. Norwood, if you go to N-11, IR-3, please?

BY MR. MAHODY:

Q. And here in the bottom half of the response it indicates the PHP does not have a specific quantification of those costs. Those are the operational costs associated with dispatching. And I -- Mr. Lock, I heard your testimony earlier, it's not that I didn't, but I just wanted to confirm that despite all those references you made in your testimony, on the record of the proceeding there's no specific quantification of those operating costs, is there?

A. (Lock) I think that's a fair statement. There's no specific detailed quantification of those costs, outside the generalizations, if you want to call them that, and not specific that I provided earlier and happy to yeah, further...

Q. And from an order of magnitude perspective, Mr. Lock, are you -- do you have an idea of approximately what those amounts would have been that have been spent, invested by PHP in relation to those items?

A. (Lock) Over the years we have

discussed it at length, myself and my colleague, the co-mill manager, who manages the paper machine in terms of impacts to the infrastructure; that is, PHP. It's about $750 million of infrastructure there when it was built back in '98. And we've spoken at length on the wear and tear, the toll that this up and down operation of a entity that was designed, engineering-wise, to run at a very constant, or once it's up and running, stay running for a number of days, and running it in a very different mode is having on a whole host of items, but we've not tallied that up, you know, in a specific way.

Q. Is it not, though, PHP's position that part of the justification for PHP receiving 100 percent of the dispatchable credit is that PHP has incurred those costs, those types of costs, in order to occasion that credit?

A. (Lock) Yeah, I think it's -- the way I would characterize it is we're looking to have, you know, the risk of those costs, because it's really a risk

calculation more than actual quantifiable specific costs, that to be able to continue to offer this load flexibility, which adds significant risk to starts and stops on that equipment, that the -- our intent is to make sure that that risk is mitigated like an insurance policy, if you will, on what we know will happen someday when we start up and we incur a major crash or smash because of that moving the line up and down as frequently as -- you know, last year we -- 425 times we moved more than 50 megawatts hour to hour. So that's a significant number of events in the run of a year for a machine in any other jurisdiction that would run very consistently throughout, you know, a number of weeks and shut down for maintenance returns. And we're operating very, very differently.

So it's really -- if that makes sense. I don't -- risk balance that we're making with -- to continue to offer it. And we know that the age of the asset is, you know, getting on there, and the constant cycles are cumulative, in terms of when you warm up a

large motor and there's, you know, everything of degradation of insulation in the motor, there's, you know, wear and tear on the bearings; starting, stopping, sitting at idle. So it's very hard to specifically quantify. And the way that we've looked at it is there has to be some compensation, like there is in many other DR schemes through various jurisdictions, and where large industrial loads are used in systems that have higher and higher variable generation as an input.

We recognize the need, but we also have a -- we're commercially sensitive in terms of knowing that that is impacting the life and the wellbeing of our -- of our equipment.

Q. Sure. Based on the evidence, I'm not seeing the issue as being about some sharing, but this is an instance in which PHP is saying, "No, we should get 100 percent of this benefit," and it's justified, at least in part, on an unspecified cost, and now with the risk associated with an unspecified cost. And it -- do you see

what I'm getting at?

A. (Lock) Well, I look at it slightly differently. We're offering a service which is providing ourselves an optimal cost of generation. And if we choose not to -- to do that, it wouldn't be optimal, and it would be no different because the utility would continue to provide service to others. This is just an opportunity for the use of our load at optimal times to minimize such straightforward things. I think as Mr. Fitzhenry had mentioned, you know, spilling of wind or things like that, not due to anyone else's actions or any other great class's actions, but our own. So we would expect full compensation for our service that we're providing.

So it has nothing to do about making the -- we're trying to, within our ownership and within the management group, you know, make sure it's worth our while to do that because it is a significant challenge for our operators and our or equipment as it -- as it ages.

Q. Let me turn to the topic of dispatchability itself, and if I could start with helpful references, your reply evidence.

MR. MAHODY: It's N-37, Mr. Norwood, at page 10, please. And I think I'm around line 25 or so.

MR. NORWOOD: Page 10 or PDF page 10?

MR. MAHODY: It is -- just give me one moment. Mr. Norwood, I'll have it here. PDF page 10, I believe, down near the bottom.

BY MR. MAHODY:

Q. And here, just beginning at line 22, Mr. Lock, it indicates:

> In its evidence Bates White puts forward that PHP will have a greatly reduced incentive to respond to price signals. In the first instance, PHP has no visibility to price signals on the system, [it] is entirely Nova Scotia Power's purview. PHP responds to supply availability, and PHP is dispatched to run when there are available [megawatts] on the system.

You next say so ---

A. (Lock) Sorry, sir, I don't think

that's the document. Just reading from the monitor, I'm not following your -- I think I'm with you on my paper copy, but just for everyone's benefit, ---

Q. Thank you.

A. (Lock) --- that's page 10, the printed -- the document number and you're starting at 22 with the answer?

Q. Yeah. "In its evidence Bates White..."

A. (Lock) Got it.

Q. Okay.

A. (Lock) Thank you.

Q. No, thank you.

And then if we go down to line -- I'm at the end of line 25:

> When there are supply constraints PHP is dispatched down. This is entirely a [Nova Scotia] Power driven process.

Can you confirm for me, Mr. Lock, that the concept that you're referring to there is

interruptibility, not dispatchability?

A. (Lock) Sorry; just wanting to review for clarity because it is a confusing differentiation.

Q. Yeah.

A. (Lock) I have to believe that this is referring to the dispatchability portion and not interruptibility. Because it's a common misconception that we're responding to price signals, which I think you realize that there's no price passed back and forth; it's a operating mode, as we went through earlier. And PHP has no visibility to price pairs or price signals. And so I believe this is referring largely to the dispatchable portion of the rate.

Q. But under the rate, Mr. Lock, what you receive is a schedule from Nova Scotia Power.

A. (Lock) Correct.

Q. And at that point, you're put in a decision; you can either abide by that schedule, or you

can move through that schedule; correct?

A. (Lock) Correct.

Q. It is not a completely Nova Scotia Power-driven process, is it? PHP has discretion as to whether or not it chooses to follow the schedule that Nova Scotia Power or the System Operator provides?

A. (Lock) In the case of dispatchability portion of the tariff, that is correct, and if it -- in this case, if that's what it is, then you are correct that it's -- Port Hawkesbury does have an ability to, in some cases, a limited amount, as we have seen in prior rate, to operate through. But it's -- that is not the fact with the interruptibility rider which provides Nova Scotia Power the ability to solely drive where our load is, so...

Q. Yes, and in response to questions from Ms. Rubin around 2 o'clock this afternoon, I had marked down where you'd said the big stick of interruption. And that is -- that's the stick, isn't it?

Interruptibility under that tariff, that's where the direction for you to immediately shed load comes from; correct?

A. (Lock) In emergency system cases, you know, following the interrupt protocol, yes, that is a -- there is no choice for Port Hawkesbury to vary from that without a significant penalty, as provided in the interruptibility clause. The rest of the time and the rest of the calls or schedules and then the dispatch above and beyond the schedule that's provided by the real-time desk, but that of the System Operator, we also comply with and we've been providing, you know, I think a very good compliant compliance; a high degree of compliance to those schedules.

Q. Yes, but that compliance that you're providing is a choice that the mill makes whether or not to comply with those dispatch schedules.

A. (Lock) Correct.

Q. And do I understand it, Mr. Lock,

that PHP's view is that it has no visibility to the pricing of energy that's being produced to supply its load in real time?

A. (Lock) We don't -- do not see a dollar per megawatt. We obviously have some idea of the cost of combustion turbines, so -- if we do see combustion turbines turning on. But as far as the cost of any other generation, we don't have a direct knowledge and we also don't know which electrons coming from which until after the fact, which units or which form of generation it's coming from until the end of the year underneath the ELIADC, or in this case, would be at the end of the year as well.

Q. I had read the draft tariff and the operating procedure a little bit differently. And let me just give you a chance to take a look at that.

MR. MAHODY: Mr. Norwood, if you could call up Exhibit N-6 and the rider operating procedure is -- that begins at page 1390.

BY MR. MAHODY:

Q. And, Mr. Lock, the section I want to ask you about is over at page 1393.

MR. MAHODY: Mr. Norwood, please. And it's down towards the bottom of the page. And it's the section that, yes, if we can just move up a little bit?

BY MR. MAHODY:

Q. It's "Nova Scotia Power and PHP agree...." And I'll just give you a chance just to review that clause, Mr. Lock, and I just have a question for you about it.

(SHORT PAUSE)

MR. LOCK: Yes. Thank you.

You good, John?

BY MR. MAHODY:

Q. Do you agree that the system information that's referenced in that section is information that is relevant to the price of energy on Nova Scotia Power's system?

A. (Lock) It could be inferred from the amount of different mixes. But coming to Port Hawkesbury we don't -- that system information is not specific to Port Hawkesbury -- generation serving Port Hawkesbury; it's generation in the entirety of the province. And really it's just a continuance of some system information that we have seen and exchanged from the utility. So it's -- it characterizes the system conditions.

So as I said earlier, one can infer from, you know, the -- a combustion turbine, you know, we can get a general price, but we do not know specifically, you know, the coal price on a given day or what that would have been able to do in terms of cargoes or any of the FAM handling of that -- those fuel inputs.

So yeah, no price. We do I think it's fair to say, that during times of high system constraints, we know it's expensive, but not a -- not a direct drive price.

Q. And I didn't mean to ask you about whether or not it tells you the price. What I was asking is whether or not that information that's referenced in this paragraph is information that is relevant to the pricing. And you agree with me, it is:

> On an automated basis, [Nova Scotia] Power will provide PHP with information in respect of its system demand and the aggregation of generation types (specifically coal, gas, oil, combustion turbines, imports and hydro) as a snapshot of the current system condition.

That's relevant to the price. You agree?

A. (Lock) Yes, it would be relevant to the price, but the utility that we've seen in it is when the System Operator or there's a failure of generation, we can respond very quickly, having seen that event live in real time. So it helps in the responsiveness, if you will, of our decisions.

MR. MAHODY: Mr. Norwood, can we go back to Exhibit N-37 at page 10 where we were?

BY MR. MAHODY:

Q. And I'm down near the bottom of that paragraph, round about line 29, Mr. Lock, and I wanted to ask you where you say here in your reply, beginning in line 29:

> When Bates White states that, 'no matter the condition on the system or the cost of energy....' this ignores the fact that there will be multiple conditions on the system, at any given time, that will constrain PHP's ability to run, regardless of the price of energy on the system.

Can you elaborate, Mr. Lock, what you're referring to by the "multiple conditions that will constrain PHP's ability to run"?

A. (Lock) I think what we're trying to get at there is there are other conditions on the system; there could be transmission constraints, we could lose imports. We -- there are multiple conditions that could exist at any time, that will impact our ability to run. Our steam supply from the biomass plant could be impacted as well, impacting our ability to run. There are

-- there's more than one system condition that can impact our ability to run that doesn't relate to what the price of energy is.

Q. So there's the supply of steam from biomass, and Mr. Esaiw, what else? What are the other.

A. (Esaiw) There could be transmission constraints.

Q. Okay.

A. (Esaiw) We could lose our imports from other jurisdictions.

Q. Internal?

A. (Esaiw) There could be all kinds of internal issues with power generation. Again, these affect our ability to be dispatched. And it's not necessarily a price of function. It's much more a function of the operation conditions on the system at the time.

Q. A couple of questions on Goose

Harbour. And could I begin by turning to your reply evidence on this exhibit at page 3, line 24?

MR. MAHODY: I'm thinking it's a PDF reference, Mr. Norwood. We're about to find out. N-3, yeah. N-37, sorry, page 3. Next page. Yes, it's that, down near the bottom.

BY MR. MAHODY:

Q. "Why is the P90 utilized with respect to wind projects?"

So here, down at line 24, you indicate, "The P90 level of wind production is used as a standard for financial calculations."

Can you just explain, Mr. Lock, what's meant by the P90 with respect to wind production?

A. (Lock) So there's a number of probabilities. I'm not going to get it as good as maybe the dictionary definition of the various probabilities of exceedance, but the P90 production level, there are a few others that are used in project financing. The P90 level

is the level that our lenders had identified with the experts from DNV who look at the range out over a -- based on meteorological studies that were done on the site and then translate that into a turbine-by-turbine probability of energy generated from each of the turbines. And the P90 level for wind is what they had instructed the -- and we then financed against. So not going to show my ignorance around the -- I can't explain the P90 B50 constructs. What I can say is that the -- what was used, and as we said here, you know, the lenders then ensure that it will generate enough revenue to cover the debt in this approach with the P90 wind forecast over the 25 years of the project.

Q. The P90 output estimate is a conservatively low number; do you agree?

A. (Lock) I think it's a -- it's a number that is used commonly in the industry. I'm not going to comment. I don't have a personal understanding of its, you know, conservatism versus others. But what I

can tell you is that it is the choice of our lenders and what we have financed against.

Q. One would expect the P90 level to be exceeded in nine out of every ten years; is that correct?

A. (Lock) That's -- yes.

Q. Are you comfortable classifying the P90 as a bad wind year?

A. (Lock) No, I'm -- again, I don't think so.

Q. And in your evidence, you go on to talk about that the P90 level is crucial for lenders, and you've indicated that here today. But what is the possible relevance, Mr. Lock of the P90 output level for the ELID energy charge? Why would you be using it for that purpose?

A. (Lock) That is the expected energy for that investment, and by extension would be the expected amount of energy to flow. That would be through

the Power Purchase Agreement and then on through the Power Sales Agreement. So that's -- that is the best expectation built on industry standard and detailed modelling from DNV.

Q. You say here at line 24, though, beginning there:

> This level is crucial for lenders to ensure that the project can service its debt even in a bad wind year.

And I understand the distinction that you're making about what financial experts look at, and I'm not quarrelling with you on that front, but it's also PHP's position that that same P90 estimate should be utilized for the output assumptions for the creation of the ELID Tariff?

A. (Lock) Yes, it is.

Q. And why is it not the P50 that you're recommending?

A. (Lock) The P90 is what we feel is appropriate for both. And that's when one looks at it,

it's a highly variable resource, the wind that's out there. And I think there's a number of factors that can happen. So we believe it's appropriate to use P90 both for the purpose of the financial arrangement that is the PPA and the PSA, as well as using to look at the net energy that would be needed in this tariff.

A. (Esaiw) Just also confirming the P90 was required in our submissions to the System Operator and the applications for the wind farm as well.

Q. I'm not asking about where it was to be included, I'm asking why it's included as the basis for the ELID output forecast for Goose Harbour and why it's not P50 that's being utilized? Because I understand that P50 is 50 percent of the time you'll be above the number, 50 percent of the time you'll be below the number. That seems to me to be a reasonable starting point for planning purposes, but you think otherwise.

A. (Lock) That's correct; we think otherwise.

Q. And at a very high level, and I do mean high level, if we look at the PHP -- the calculation of PHP's net load as you are requesting this be established, we would start with PHP's gross load. We subtract the gross -- the Goose Harbour Wind output, and we arrive at a PHP net load. Have I generally got that correct, Mr. Lock?

A. (Lock) Yes, as outlined at the -- below -- just slightly below the page that we're seeing on the monitor there, yeah, walks through that forecast and nets off the P90 value of 528, it would result in four -- 246 -- 246,000 megawatt hours.

Q. And what is the consequence of utilising P90 versus P50 for the Goose Harbour window put on that calculation?

A. (Lock) I would have to subject to check and look back at the report, which is -- which is a report to lenders, in particular Table 3.2 of that that outlines the various energy levels. But could look at

that, if you so choose.

MR. MAHODY: Mr. Norwood, on the same page, could we scroll down just a few more lines?

BY MR. MAHODY:

Q. In this next question -- right there is good; thank you -- you ask yourself:

> Using the forecast load of 774 [megawatt hours] which PHP is provided to NS Power, and P90 value for 168 [megawatts at] 528,000 MWH yields what net load to be served by [Nova Scotia] Power.

And you have 246,000 megawatt hours.

Can you just describe to me how that calculation was made?

A. (Lock) So as you -- so the 744, which is the load forecast that we put forward in terms of the gross, as you described it, and then we take off the 528 -- just trying to do the math here -- to come up with the net load of 246,000.

Q. And can you do that same calculation by utilizing the P50? Or if you've done it,

do you know the number.

A. (Lock) Not -- we have not done it. Are you asking for an undertaking? Sorry.

Q. Would it be you could do that?

A. (Lock) We could look at the -- back at that information that would have been provided, sure.

MR. MAHODY: So, Mr. Chair, I would ask for an undertaking that the answer to the question at the bottom of page 3 in the undertaking response would be based on undertaking response on the P50 value.

MR. LOCK: And just to be clear, this is looking at the full 168, so after the second SIS; that's what you're looking for, not the 130.5; correct?

The current -- the -- currently, for example, the P50 value for the 130.5 is 507, not the 528.

BY MR. MAHODY:

Q. No, I would take it on the same premise.

A. (Lock) Same premise, okay.

Q. Yeah.

A. (Lock) No, I -- just for clarity, I just -- that's what we will provide.

THE CHAIR: Undertaking U-21.

UNDERTAKING U-21 - To reformulate the answer to the question at line 31-32 of Exhibit 37, PDF page 3, based on P50 instead of P90

BY MR. MAHODY:

Q. You -- it was mentioned earlier in this hearing that the Goose Harbour facility would mirror the behind-the-meter type of project. And I think there's reference to it in your pre-filed evidence as well. You recall that to you?

A. (Lock) Yes.

Q. And in what way do you see the Goose Harbour project mirrors a behind-the-meter project?

A. (Esaiw) So we get credit for all the megawatts PHP wind produces, even though it's not behind the fence.

A. (Lock) Minus the credits flowing from that for the records. Without the REC credits.

A. (Esaiw) Without the REC credits, yeah, just to clarify.

Q. But as a general matter in an actual behind-the-meter arrangement, what happens when generation exceeds load?

A. (Esaiw) I guess it depends on the type of arrangement you have with your utility. You could put those extra megawatts onto the grid or you would have to -- again, it depends on the -- any commercial arrangement that could be made, whether you're simply ramping down your generation or putting some of the excess onto the grid. Those both are arrangements that exist.

Q. And if you didn't want to put it onto the grid and you wanted to keep it for your own later

use, the customer would need some method of storage, would it?

A. (Esaiw) In a very different construct, yes.

Q. But to the extent that Goose Harbour may or may not mirror a behind-the-meter situation, there's no cost of storage that is being incurred, is there?

A. (Lock) There's no anticipation that there would be more generation than use at Port Hawkesbury. And your hypothetical question around energy or storage of that is, you know, I guess from a calculation perspective, is possible. But, you know, even at the P50 number, you know, there still would be need for electricity coming from the grid and -- that we would not exceed, but for the provision of the month-by-month rollover in some particular months. But in the full year, we expect to use all, and more, than what the wind project will generate.

Q. Thank you, gentlemen.

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

Thank you.

THE CHAIR: Thank you.

Mr. Melanson?

QUESTIONS FROM MEMBER MELANSON

Q. Yes. I only have a couple of questions. The first one is with some trepidation that I go back to the idea of dispatchable and interruptible power and the questions that Mr. Rubin asked about. And I believe the -- one of the answers was that in the specific case that was being discussed in that example, there was both a dispatch request and interruptible protocol introduced at the same -- for the same -- at the same for the same period, roughly. Is that right?

A. (Lock) That's correct. The first -- in first instance, there would have been a dispatch, and then as system conditions tightened, the System Operator obviously invoked the interruptibility.

Q. But my question is, since we looked at the numbers, it goes from 13 to 9 to 4, which is effectively zero for PHP, to 4 and back up. In that scenario where there's a request, if I follow the numbers, the coding correctly, there was a -- there was a request

for -- to ramp down on dispatchability to zero. Is that right? Was that right?

A. (Lock) For Port Hawkesbury purposes zero, but the 4 megawatts would be station service power that because the ---

Q. Sure.

A. (Lock) --- meter number there represents both Port Hawkesbury pure plus the station service power that's provided to the biomass generator, so...

Q. But my point of my question is let's say 4, then.

A. Yeah.

Q. And -- but the point of my question is at the same time, were you being asked to dispatch down to 4 and also the interruptibility -- the interruptible portion of the tariffs are being invoked to drop you to 4. Was it the same -- is it two things that were asking for the same -- two requests that were asking

for the same thing?

A. (Lock) So the timing would be slightly different. So what is sort of the hourly resolution, there would have been an ongoing request to utilize, through the demand response aspect, dispatching down from the schedule that had been provided by marketing. And then as the system continued in sort of minute by minute within the hours that -- the period that we were dispatched down, there was a need to get down even further. So they invoked that, which for us, the -- it's very different in that we then to absolutely achieve that, we open up breakers that cut the mill load free of the system.

So everything above that, like getting to, let's say, 4.5 megawatts is not good enough to get to zero. Zero means zero. So they would have, to get that extra bit, gone through that procedure. We opened up the breakers. Nova Scotia Power could have as well because like other telemetry customers, they can also remotely

activate those breakers. But we -- our team opened up the breakers.

Q. So that from a perspective of the operation of the mill, the actual response to the request is different because the interruptible request is absolute; you have to get down to that number or you can face penalties?

A. (Lock) Yes, that's right. It's another level of penalty and seriousness. So it's seen as distinct, and that could overlay instead of being at 13, we could have been at the -- at some other higher level. And if there was a major impact, like loss of a Point Aconi or something like that, there could have been some other conditions that we would have been called for interruption of a greater amount immediately.

Typically, as you see through some of the hourly data that Ms. Rubin walked us through, is Port Hawkesbury's load, well in advance of that level of urgency, has been put where the System Operator finds it

to be most convenient. In some cases held in reserve because they know exactly, through their metering, how much load they would gain by taking us down. So similar to others that now are on telemetry versus in the past, when you'd be kind of blind going through the list in terms of seeking an interruption, not knowing the result. Today, telemetry plus Port Hawkesbury load is known know very definitively, and the practice has been that the compliance is very high.

Q. And with dispatchability, if there was no interoperability invoked, does Nova Scotia Power have the same level of confidence that they can count on the fact that it's going to be -- the power is going to be at a certain level?

A. (Lock) I think the answer to that is no, that that's not the same. We -- Port Hawkesbury, as Mr. Mahody just walked us through, is that Port Hawkesbury does have some discretion whether it complies with that dispatch request. And that's the

differentiator. In all but, you know, 2 or 3 percent of the time we have complied, but it's not 100 percent, which the interruption call makes it absolute 100 percent.

Q. And when you're in a situation of system emergency, that absolute number might be important?

A. (Lock) That -- yes. Yeah. So that's why there's this hierarchy of regular flows. And like I said, this is happening very regularly. You know, even in the -- like I said in the past week, we're called upon by the System Operator to drop load. We were asked because of a loss of a -- of a coal unit and Maritime Link being out of service and also Point Lepreau being offline, Nova Scotia Power is essentially an island or the system last Tuesday, and we were asked to drop 90 megawatts, which we -- which we complied with in 10 minutes. No. Well, it was actually 12 minutes from the -- from the time we got the call. It would have to have been 10 minutes if it was a call to zero.

Q. Okay. I've got a question about

forecasting because I realized that in your Opening Statement and your evidence, you discussed the idea of not having the most up-to-date forecasts for the energy demand component. But my question is more general. This tariff -- the anticipation when the Settlement Agreement was signed, was that that this tariff would come into effect on January 1st, 2026; correct?

A. (Lock) Correct.

Q. And at the time, the dispatch was that all other rates would have a rate by January 1st, 2026. I know that didn't happen for all the other rates either, but that was the anticipation when the Settlement Agreement was signed; correct?

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

Q. And there were a lot of forecasts that go into ratemaking. You would agree with that; correct?

A. (Lock) Yes, absolutely.

Q. And for above-the-line rates

ordinarily you don't get -- I know there are mechanisms like the FAM, those various specialized situations. But ordinarily you don't get to true-up your forecasts after the rate application is concluded and the rates are set until the next application. Isn't that correct?

A. (Lock) I guess, yes, in general, but in this specific case there was no rate. There was a general rate agreement, a Settlement Agreement. But as we've -- you know, have in our evidence, and as we've talked about through the settlement terms, we believe that we had the opportunity. And because we're such a large load, we've always felt that having the most up-to-date forecasts like we've had been providing in the below-the-line case of the annually adjusted rates, that we would provide the most up-to-date forecast. And given the trade concerns with the south of the border -- 95 percent of our material goes south of the border.

Q. Sure.

A. (Lock) So, you know, we --

obviously there's lots of puts and takes, as you say, in that, but our ---

Q. It's not so much that. It's that what chance do the other ratepayers have? I mean, the cost of service is set up, rates are developed from that. And what chance do other rate -- above-the-line ratepayers have to adjust other forecasts that were not -- turn out not to be accurate during the rate period? And why isn't it fair to just use all the same forecasts for all the above-the-line forecasts that were set up in the rate case for all the above-the-line customers?

A. (Esaiw) I think the reason we wanted to use the most relevant information was it's a new tariff and we want to get it right out of the gate for the first time. We heard from Nova Scotia Power, I believe, that their processes start with a forecast from other rate classes and those end up getting trued-up in some other way -- fashion if they get their loads wrong at the end of the year. So there's some balance there, I believe, too,

but I think our premise is that we just wanted to start off on sound footing with more relevant and recent data.

Q. Okay.

Thank you. Those are my questions.

QUESTIONS FROM THE CHAIR

Q. I'm just going to pick up where my colleague left off, then.

In terms of the forecast, you want to use the most up-to-date forecast because at this point in time, you believe it's the most accurate?

A. (Lock) That's fair. Correct.

Q. And from your perspective, that's what you're driving for is to get the most accurate forecast as possible when you set this new rate; correct?

A. (Lock) Correct.

Q. And so when it comes to the P90 forecast for production from the wind farm, my understanding is P90 means there's a 90 percent chance that the energy level is actually going to be higher; correct?

A. (Lock) That's what I understand as well.

Q. And so it's your company's

position that an estimate that is 90 percent probably going to be higher is the most accurate forecast that's available to be used?

A. (Lock) That is our position; correct.

Q. Okay. In terms of the Goose Harbour facility, what's the status of construction?

A. (Lock) Currently we have 21 of 24 turbines fully erected and two of four circuits energized, all of the substation switchyard is commissioned, and there have been turbines putting energy onto the system as of two weeks ago. And we're walking through the Nordex, who are the technology supplier, and their ramp-up of those turbines and meeting all of their technical due diligence on start up.

So we actually have now six turbines that have been passed over and are working through meeting the requirements of the IESO, comparing the signature of those generation to the models that were used in the

system interconnect studies.

Q. Okay. And so you have 21 or 24 turbines, I think you said. When do you anticipate the 24 -- all 24 will be up?

A. (Lock) The -- our anticipation is before the end of the year. More specifically, the COD that we have in place is December 15th. So there's a number of things ongoing out there at the moment on those other three sites that are holding us up. We would have liked to have those already standing, but we're waiting for some foundation work to be completed.

Q. And am I correct that the 24 turbines, that gives you the total capacity of 168 megawatts?

A. (Lock) That's correct. But at the connection point, that will be constrained until such time the second SIS interconnection is fully approved.

Q. Okay. But as they say, I guess, if you're putting up 168 megawatts of wind turbines, I

think confidence must be high that you will actually get that approval?

A. (Lock) Yes, so far, and the back-and-forth exchanges in terms of the signature, it's the same turbines that are going from the 130.5 to the 168, so we're feeling confident that that will be put in place. Just the timing is fairly long, and those processes of interconnection.

Q. Okay. Thank you.

And then just a final couple of questions here, just so I'm clear on what the Port Hawkesbury Paper's proposal is.

So I understand you're asking the Board to approve a demand charge that's based on 8 megawatts?

A. (Lock) That's correct.

Q. As your preferred scenario. And in that scenario there would be no need for an interruptible credit?

A. (Lock) I must apologize; my head's getting a little turned around here today, this late in the afternoon. I'll defer to my colleague on this one.

A. (Esaiw) I believe we'd be foregoing the interruptible credit, yes, at that point. But we'd still want to be priority interruptible.

Q. Okay. So that ---

A. (Esaiw) Yeah.

Q. --- was going to be my questions. Even though there's no interruptible credit that's provided, the load above the 8 megawatts, whatever it might be, would be fully interruptible.

A. (Esaiw) Yes.

Q. And priority interruptible, even though there's no priority credit either in that circumstance?

A. (Esaiw) Well, I think if we -- if the 8 megawatts was confirmed, there would be no

interruptible credit; I believe that's the way it works. But for us to remain priority interruptible, there would be an expectation of the current priority interruptible credit coming our way.

Q. What's 10 percent of zero?

A. (Esaiw) I understand the math doesn't work out there.

Q. So what would you suggest would be the priority premium -- or the premium that you would get for your priority interruptibility in that circumstance? I didn't see anything about that in your -- in your evidence.

A. (Esaiw) I think NSP has said that they would need to do more work on the priority interruptible, so we would expect that to happen. But I do expect there would be some kind of compensation with being priority interruptible. If there wasn't compensation, I don't see why we would be.

Q. Okay. Thank you very much.

THE CHAIR: Anything -- I'm just going to go generally; anyone have anything arising from Board questions? Mr. MacDougall, anything, either Board questions or re-direct?

MR. MacDOUGALL: Yeah, I have a small amount of re-direct, Mr. Chair.

RE-DIRECT EXAMINATION BY MR. MacDOUGALL

Q. Good afternoon, gentlemen.

Earlier today, there were various questions asked about the wear and tear on equipment and the impacts, both operationally and commercially. I was wondering if, for the Board, you could comment on how often the ADC is called upon during the year on a regular basis.

A. (Esaiw) Multiple times a day. On average, I think when we look at the last couple of years changes from a levelized load level of at least three times a day we would be moving our load around.

Q. So at a minimum of three times a day?

A. (Esaiw) Yeah.

Q. And would there be many days when you'd be moved around more than that?

A. (Esaiw) Yes. Yes.

Q. Thank you. And the ADC operates

all 8,760 hours of the year; is that correct?

A. (Esaiw) That's correct.

Q. And you get an energy credit, or it's proposed that you get an energy credit for that?

A. (Esaiw) Yes.

Q. But there's no proposal that you get paid any demand credit for moving your load with respect to the ADC?

A. (Lock) That's correct.

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

THE CHAIR: Thank you, Mr. MacDougall.

Thank you very much, panel. Appreciate your patience. It's been a long day, but I appreciate your perseverance.

MR. LOCK: Thank you.

THE CHAIR: Thank you.

(WITNESS PANEL WITHDRAWS)

THE CHAIR: It's 4:30 now. I think I

would like to try to get through another witness if possible, or at least partially into another witness.

Mr. Roberts?

MR. ROBERTS: Our folks, I believe, have been listening and are ready if you wish them to come on.

THE CHAIR: Just before we do; I heard, Ms. Rubin, there may be some issue with Mr. Bowman or...?

MS. RUBIN: No, the only issue we had raised was if it appeared that he would not be able to complete his cross-examination tomorrow, we would put him on before InterGroup. But I don't think we should have an issue. But I wonder, before we can go to the InterGroup witness, we just -- could we just have a quick break to ensure that we've got childcare covered?

THE CHAIR: Yes, of course. Yes, no problem. So we'll take -- we'll take a quick 10-minute break here now.

Thank you.

MS. RUBIN: Thank you.

--- Upon recessing

--- Upon resuming

THE CHAIR: ...good to resume here.

Were there any issues with childcare? We're okay? Well, appreciate it. Thank you very much.

Mr. Roberts?

MR. ROBERTS: Thank you.

I see Mr. McLaren there. Mr. Mahmudov? There we are. Thank you.

That's Andrew McLaren and Hayitboy Mahmudov are available to be affirmed.

THE CHAIR: Mr. McLaren, can you hear me? Okay.

MR. McLAREN: Yes, I can hear you. Can you folks hear me?

THE CHAIR: Yes, we can. Thank you very much.

ANDREW McLAREN, Solemnly Affirmed:

THE CHAIR: Mr. Mahmudov, can you hear me okay?

MR. MAHMUDOV: Yes, I can.

HAYITBOY MAHMUDOV, Solemnly Affirmed:

THE CHAIR: Thank you.

Mr. Roberts.

MR. ROBERTS: Thank you.

EXAMINATION ON QUALIFICATIONS BY MR. ROBERTS

Q. Mr. McLaren, Mr. Mahmudov, you're both employed by InterGroup Consultants?

A. (McLaren) I'm a Senior Associate at InterGroup, so I have a relationship with them. But I'm not an employee; I'm a contractor.

Q. Thank you.

And Mr. Mahmudov?

A. (Mahmudov) Yeah, I am in a similar relationship with InterGroup. So I am an Associate of InterGroup.

Q. Thank you. And you jointly prepared a report for the Consumer Advocate regarding this matter, which is filed as Exhibit N-19 in this proceeding?

A. (McLaren) Yes.

Q. Okay. And you also assisted the Consumer Advocate in providing responses to information requests, Exhibit N-29 and Exhibit N-30?

A. (McLaren) Yes.

Q. And prior to that, you both provided advice to the Consumer Advocate concerning the 2025 General Rate application of Nova Scotia Power, and the Settlement Agreement, which was filed as part of the General Rate Application?

A. (McLaren) Yes.

Q. Okay. Attached to Exhibit N-19 as Appendix A to your report are copies of your *curriculum vitae*, and I'd like to briefly go through them.

Mr. Mahmudov, yours is first in the document. Pages aren't numbered sequentially, but it's

Appendix A. Thank you. And could you summarize your professional background and experience for the Board, Mr. Mahmudov?

A. (Mahmudov) Yes, certainly.

So I have a Master's degree in economics from the University of Manitoba, and I am also a Certified Depreciation Professional. I have over 17 years of consulting experience in the utility industry with a particular focus on the electricity and natural gas sectors.

I have provided a review and analysis related to revenue requirement, cost of service, rate design, and depreciation matters, including preparation and submission of expert evidence, and also provision of expert testimony before regulatory tribunals in regulatory proceedings across Canada, including in Ontario, Alberta, Yukon, and the Northwest Territories. And yeah, my experience is detailed in my résumé, as Mr. Roberts mentioned, in Exhibit N-19.

Q. And although this is the first time that you've been qualified to provide expert opinion evidence to this Board, as you've indicated, you have done so before the Alberta Utilities Commission, the Public Utilities Board of the Northwest Territories, the Ontario Energy Board, and the Yukon Energy Corporation?

A. (Mahmudov) Yukon Utilities Board, yes.

Q. Thank you.

And, Mr. McLaren, your CV is next in line at the Appendix A.

A. (McLaren) Yes.

Q. Thank you. And could you summarize your professional background and experience, please?

A. (McLaren) Yes. I have a Master's degree in Natural Resources Management from the University of Manitoba and a Bachelor's degree in Environmental Science. I have about 25 years of experience working in

the utility regulatory sector, working with electric natural gas utilities, as well as water, wastewater, stormwater, municipal utilities.

I have testified before the Manitoba Public Utilities Board, the Northwest Territories Public Utilities Board, and the Nova Scotia Regulatory and Appeals Board.

Q. And I thank you. What about Newfoundland and Labrador?

A. (McLaren) I've prepared evidence in that has been submitted to the regulator there. I've also prepared evidence that has been submitted -- written evidence that's been submitted in Alberta on a number of occasions. And I've participated in settlement negotiation processes in those jurisdictions but not testified.

Q. Thank you.

MR. ROBERTS: Mr. Chair, Mr. Melanson, the Consumer Advocate proposes that Mr. Mahmudov and Mr.

McLaren be qualified as expert witnesses, able to provide opinion evidence on utility regulation, including revenue requirement, rate design, and cost of service.

THE CHAIR: Any questions on qualifications, or objections?

Okay. They're so qualified, Mr. Roberts.

MR. ROBERTS: Thank you.

DIRECT EXAMINATION BY MR. ROBERTS

Q. I'd ask you to return to Exhibit N-19, your report. You've indicated that you jointly authored this report. Is the information contained in your report true, to the best of your knowledge and belief?

A. (Mahmudov) Yes.

Q. Do you jointly adopt the report as your evidence in this proceeding?

A. (McLaren) Yes, I think that's fair. I think there are certain sections that are more Mr. Mahmudov's sphere and others that are more mine, but I

think we can sort out as we go which of us are the right people to respond to different topics.

Q. Thank you. Do you wish to make any corrections to your report?

A. (McLaren) I do not have any.

Mr. Mahmudov?

A. (Mahmudov) I do not have either.

Q. Thank you.

Since your report was filed, both Port Hawkesbury Paper and Nova Scotia Power have submitted reply evidence at Exhibits N-36, 37, and 38, respectfully -- respectively; sorry. Did you review that reply evidence?

A. (McLaren) Yes.

Q. And does it cause you to change any of the opinions and recommendations you've provided in your report?

A. (McLaren) No.

Q. Thank you.

MR. ROBERTS: Thank you. The witnesses are ready for cross-examination.

THE CHAIR: Thank you.

Ms. Power?

MS. POWER: No questions from Nova Scotia Power. Thanks.

THE CHAIR: Small Business Advocate?

MS. POWELL: Thank you, Mr. Chair. We have no questions.

THE CHAIR: Industrial Group?

(SHORT PAUSE)

CROSS-EXAMINATION BY MS. RUDDERHAM

Q. Good afternoon, Mr. Mahmudov and McLaren. I have what I hope will be a quick series of questions, and I'll direct it just outwardly and you can decide amongst yourselves who's best to respond. Okay?

So just a moment ago, the Consumer Advocate went over your experiences and qualifications. And I won't repeat it, but I want to confirm; you're not a lawyer, neither of you, and have no experience in legal interpretations; correct?

A. (McLaren) Correct.

Q. You don't have experience or expertise in the legal principles of contract interpretation; correct?

A. (McLaren) Correct.

Q. And in your evidence, one of your key findings is that the Settlement Agreement, which was filed with the GRA, dictates what the ELID Tariff should look like. Fair characterization?

A. (McLaren) Yes. I think in the capacity of people who work on these negotiations in other places reasonably often and are party to those types of processes, yes.

Q. Okay.

MS. RUDDERHAM: And perhaps, Mr. Norwood, if you don't mind pulling up Exhibit N-19, which is InterGroup's evidence, and specifically PDF page 9, which would be page 7 of the report itself.

BY MS. RUDDERHAM:

Q. And I'm looking specifically at the paragraph -- second-last paragraph there starts with, "However, InterGroup notes and agrees with NSP's position that the..." Sorry; it's there; "the SA expressly confirmed that," and I quote:

> ...'NS Power and PHP shall reflect the foregoing in a written tariff;' and it is open to Parties to take a position [that is] that the tariff filing is [in quotes] 'inconsistent with the load characteristics and basic tariff structure as set out above' recognizes that the Parties intended that

the SA terms would be employed in the Application to be made to the Board.

That's what that portion of your evidence states; correct?

A. (McLaren) Correct.

Q. Now, here you've synthesized the contents of the Settlement Agreement as between the parties, and you specifically say the agreement left open for the parties to take a position; correct?

A. (McLaren) Yes. I think this is speaking with reference to the Nova Scotia Power response. That's where the footnote points to, so...

Q. Okay. And perhaps we can pull up the wording from the actual Settlement Agreement itself. That's in Exhibit N-1, which is the Application. And I'm looking at Attachment 4, which starts at PDF page 30. That's the Settlement Agreement itself and the section you're referring to -- and correct me if I'm wrong -- is from Schedule A, which is on PDF page 41 and it's Item F.

That's what portion of the Settlement

Agreement you're referring to in that excerpt from your evidence?

A. (McLaren) Yes.

Q. Okay. Now, in looking at the language here, you'd agree with me that the Settlement Agreement says the parties can take "any position," not a position; correct?

A. (McLaren) Correct.

Q. And after that it says, "including whether inconsistent with load characteristics," meaning it's -- that's one example of a position a party could take, not the exclusive or defining scope of the possible positions; correct?

A. (McLaren) I think that I would say on that there's a bit of context in Part (e), in terms of the, you know, the tariff being brought forward by Nova Scotia Power and PHP, and this is, I suppose, where the dispute arises is that, from my perspective, when you read that provision, reading Parts (e) and (f) in conjunction,

it seems to me odd that the parties would write down that Nova Scotia Power and PHP shall reflect the foregoing. And then later on in (f) basically give free licence to not do what they say they'll do in Part (e). So that's kind of, I think, where the dispute arises.

Q. Sorry. And I was asking specifically in relation to the language of "including," and I believe what you're referring to is -- are you suggesting that when it says all parties, it would exclude NS Power and PHP? Is that what you're describing to me?

A. (McLaren) Well, that's the -- that's the part that I have trouble wrapping my head around, how you could commit in Part (e) to do this, and then in Part (f) basically say, but you don't have to do what you said you would do in Part (e).

Q. Okay.

A. (McLaren) For Nova Scotia Power and PHP.

Q. Okay. And for the other parties,

I assume you're referring to the other signatories on the agreement. Is that what you're...?

A. (McLaren) That would be my understanding, yes.

Q. Okay. And I was -- I was referring to the section of (f) where it says, "...including whether each of the PHP ADC and tariff filings is inconsistent..."

You'd agree that there's relevance to that language of including; it means not exclusive; correct?

A. (McLaren) Correct.

Q. Okay. Now, regardless of the specific language in the Settlement Agreement, you'd agree with me that the Board is not bound to accept or apply the contents of the Settlement Agreement for the purposes of the application for the ELID; correct?

A. (McLaren) I would agree they're not bound to. And certainly if the Board were to find

that any element of it were, you know, unjustly discriminatory or unduly preferential or otherwise not in the public interest, then, yes, the Board can and should make changes. But I also think there should be some deference to the Settlement Agreement and that if the Board doesn't think that changes it might make would rise to the level of things that were unjustly discriminatory or unduly preferential or not in the public interest, that it should give some deference to the terms that the parties negotiated amongst themselves.

Q. But you'd agree that's within the Board's broad discretion; correct?

A. (McLaren) Yes, correct.

Q. Now, if the Board were to confirm it's not bound by the assumptions in the Settlement Agreement and did not dictate the terms of the tariff to serve PHP above-the-line, would InterGroup continue to recommend that the Board approve the ELID as filed?

A. (McLaren) So this may be one

where I start and then I let Mr. Mahmudov chime in.

That was not the basis of our evidence. And I think the section that you took us to of our evidence was titled "Merits of PHP's position," given that that's what we had in place at the time.

I don't think that 8 megawatts would be reasonable, and so I think that the idea that PHP can have an operating load that's an order of magnitude higher than that, that isn't reflected in a, you know, fixed charge recovery of system costs, I would not think that that outcome is reasonable.

But in terms of what the correct number is and how to distinguish between a sort of firm operating load and a truly interruptible portion of the load, you know, we might wind up with a -- at a somewhat different number than the 57 megawatts that's in the Settlement Agreement. But we haven't changed our position on the deference to the parties to use the 57 megawatts that was agreed to.

But I'll let Mr. Mahmudov see if he has anything to add.

A. (Mahmudov) Yes, thank you.

I agree with Mr. McLaren, and in our evidence we did raise a number of concerns that we had, especially with respect to the dispatchable credit rider and also interruptible credit rider. And you know, if we were not bound or if we were thinking that, you know, the Settlement Agreement language was not as we understand it, then I don't think we would support approval of this ELID Tariff as filed by the NSP and as well as, you know, under the recommended revisions by PHP.

Q. Okay. So I want to follow up on just one thing that, Mr. McLaren, you had indicated. You had said that, in looking at the firm and interruptible, you may have wound up at a slightly different number than the 65. Can you explain to me how that would happen or why that would happen, why you would have ended up at a different number?

A. (McLaren) Yeah. I think the challenge for me on this is it's a difficult thing to point to what is a reasonable operating load to use for a baseline in setting the rates for this particular customer. Some of the information that I believe they went through with your co-counsel this morning might help sort of set an area around which you might find a number. But it is a bit of a challenge to pick exactly the precisely correct number, particularly given that the operating history we have is influenced by the tariff that was in place at the time. So it's not like we have a clear empirical record of what the exact right number is. But that type of information that was reviewed this morning, in terms of what are the volumes of power that are required to operate the business in a sort of ongoing way, would be the type of information we might point to.

Q. And sorry; when you're referring to the discussion this morning and the information about the volumes of power to operate, I assume what you're

referring to is the operating modes?

A. (McLaren) Yes, correct.

Q. And are you suggesting that it's operating modes -- do you have a specific opinion on what operating modes or what information you heard this morning that would influence that?

A. (McLaren) I have not developed an opinion on that, no.

Q. And when you say that information would be important for determining the volumes of power to operate, are you -- to operate in what way? What do you mean by that? Are you saying to operate at full capacity? Or are you saying -- like, I just want to better understand what information, in Intergroup's opinion, the Board and the other Intervenors should be looking specifically at to more accurately represent what that demand assumption should be.

A. (McLaren) Yeah. And I'm not going to have a clear answer for you. Unfortunately, it's

not something that we have spent the time to develop a specific opinion on. I think the premise or the principle for me is that if you assume that they are only there for their very sort of basic loads, and given the evidence by the company that the transmission has to be able to serve them at a higher -- has to be available at some level to be able to serve them at a higher load than that, that ratcheting down to 8 megawatts is the only number that gets put into the Cost-of-Service Study is unreasonably low.

We did hear some information today about where in the stack -- where in those operating modes that you referenced PHP needs to operate to be able to run paper machines and bleaching plants and those types of things. That type of information is what I think you would point to, but we have not reviewed it in detail to develop a specific opinion on the exact right number.

MS. RUDDERHAM: And perhaps, Mr. Norwood, if you don't mind bringing up that document? So

that's N-16 and it was previously labelled as confidential (i); it's response to SBA IR-1(a) to (c), Attachment 2.

It's the one with all the colourful boxes, Excel document that has since been put onto the public record. Yes. Do you mind? No.

BY MS. RUDDERHAM:

Q. Mr. McLaren, can you see that there on your screen?

A. (McLaren) Yes, I can see it.

Q. I assume this is the document that you were referring to and the operating modes?

A. Yes.

Q. Okay. And are you referring to the mode priority when you're saying operating at certain levels for business reasons? Can you just clarify what you meant by that?

A. (McLaren) I was, I think, referring to the configuration information about what is operating or assumed to be operating at each of those

modes.

Q. And I assume, then, what you're referring to is the row that says, "Demand Level"? Like, where it says OM-1 would be 0 to 7, you move along all the way up to OM-7 would be 140 to 160 megawatts; correct?

A. (McLaren) Yeah, in combination with the equipment configuration cell.

Q. Okay. And the equipment configuration you're referring to where it says, like, paper machine?

A. (McLaren) Correct, yes.

Q. Okay. And now, you have indicated that if InterGroup was not bound or the Board was not bound by the Settlement Agreement, you would have come up with probably a different number than as proposed, the 65? Just to be clear, are you saying the 65 is too low?

A. (McLaren) No, I'm not saying that. I'm -- and again, I want to sort of say this is a

thought experiment. It's not what -- it's not the basis on which we wrote our evidence. And so while I agree the Board certainly isn't bound by that number, that number was the outcome of a settlement that we're recommending the Board continue to use. And so I have not developed a firm opinion on what the right number would be if that Settlement Agreement didn't exist.

Q. Now, in response to an IR -- I don't think we need to bring it up, but it was an IR asked by the IG in Exhibit N-29.

Sorry; just one moment.

(SHORT PAUSE)

BY MS. RUDDERHAM:

Q. I'm going to switch gears from that question, and I am going to follow up on a comment that was made by Mr. Mahmudov.

You had indicated in the answer to one of my earlier questions that InterGroup would not be supportive of the DR credit. Am I correct on that, the

methodology?

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

Q. And I know InterGroup has not expressed support for the 100 percent assignment of the DR benefit calculation to PHP; correct?

A. (Mahmudov) Correct.

Q. Now, does InterGroup have an opinion with respect to how that load shifting benefit should be divided between PHP and other customer classes?

A. (Mahmudov) What we note there is that under the current tariff of early ELIADC other retail customers get 75 percent share of that savings with 25 percent going to PHP. And under the new tariff, the proposed tariff, that jumps to 100 percent. And the concerns that we have there is that the justification for it for that 100 percent is that, you know, PHP under the proposed ELID tariff will be now contributing towards the fixed costs as well. But under the current tariff -- ELIADC, PHP gets credits for Access Demand Control, and at

the same time they have the variable capital charge.

And that variable capital charge itself is about $1 million per year, which is now being discontinued under the proposed tariff. And I think in our estimates that was about 20 percent or 30 percent of the estimated savings under the dispatchable rider for PHP by NSP. So that, I think, in our opinion, would be the minimal amount that should be going towards the customers, but most likely it should be even higher, but I do not have that number estimated.

Q. Sorry; you said it should be 20 percent or higher attributed to other customers? Is that...?

A. (Mahmudov) Instead of zero ---

Q. Okay.

A. (Mahmudov) --- it should be at least 20, you know, 30 percent, but probably it should be even higher given, you know, the dramatic shift and the -- in our opinion, with justification for DR credit and given

all this ambiguities and uncertainties highlighted about the proposed DR credit by other consultants as well.

Q. And in terms of how the credit and the interruptible credit interact...

MS. RUDDERHAM: Mr. Norwood, if you don't mind bringing up Exhibit N-29, which is the CA's response to IG IR-4, and I'm looking specifically at 4(a).

So the question here -- do you mind just scrolling down to 4(a) there, Mr. Norwood? It's on the next page. Right there.

BY MS. RUDDERHAM:

Q. So the question asks:

> Does InterGroup consider that the risk that PHP could be simultaneously credited for both the DR and the IR for the same dispatch-down of load, represents a fundamental design problem, rather than merely an operational risk to be managed? If not, please explain.

And if you go to the answer, it just -- it says, "Yes." So has any of NSPI's evidence or PHP's evidence from earlier today provided through this

proceeding change your opinion here that there is a risk of PHP being credited for DR and IR at the same time?

A. (Mahmudov) No, it has not.

Q. And in looking to the question there, 4(c), it's asking about:

> ...does the double counting risk support Mr. Bowman's Recommendation...that there should be little to no IR credit value in the ELID tariff. If not, please explain..."

MS. RUDDERHAM: If you don't mind scrolling down to the answer there, Mr. Norwood, for (c)?

BY MR. MAHODY:

Q. So here the answer notes that the IR credit value would be included in the ELID, based on the Settlement Agreement for the test years. Then I'm looking specifically starting at line 31, it says:

> However, for future years, in the absence of a proper IR credit mechanism clearly showing no risk of double-counting the service value for DR and IR service, InterGroup supports Mr. Bowman's [recommendations] that there should be little to no IR credit value in the ELID tariff.
>
> As with my questions earlier, if the

Board were not to confirm it was bound by the Settlement Agreement for 2027, would InterGroup support the IR credit at the amount currently proposed?

A. (Mahmudov) No, we would not support that.

Q. Can you explain that to me?

A. (Mahmudov) The IR -- interruptible rider credit under the proposed ELID Tariff is justified in the Application by the distinct service it provides. But the problem that we see here is that in -- either in the Application or in the IR responses, NSPI was not able to identify, you know, the -- clearly show the evidence that IR credit is verifiable and distinctly different than from the DR credit. So a number of parties asked for that evidence. And all those IR responses are referenced in our evidence. Sorry; a number of parties asked in the IRs, NSPI for that information. And we did provide those references in our evidence. And NSPI themselves acknowledge that there is a possibility of

overlap between interoperable credit and the dispatchable rider. So, you know, that's the main concern.

But in addition to that, it was also explained that DR is an optional basically thing for PHP they can ignore. But under interruptible rider there's penalties and therefore, you know, that also justifies the additional credit for interruptible service.

I wanted to note that under the current tariff, ELIADC, there is already, you know, the same kind of penalties for -- under the interoperability section there, but currently there is no credits for interruptible.

So under the ELID we have a situation where PHP gets credit for dispatchable rider and they also get credit for interruptible rider, plus the premium interruptible. And at the same time there is discontinuation of variable capital charge. Whereas under the current tariff, you know, as I mentioned, at least interruptible service penalties are already there, with no

credit. So based on that, you know, we just cannot see a reason for duplication, basically, of a credit via both dispatchable rider and interruptible credit rider as proposed.

Q. And -- okay. Thanks for that explanation.

Is it Intergroup's opinion that the IR credit should be based on the amount of load that is actually interruptible?

A. (Mahmudov) Sorry; can you repeat it?

Q. Is it InterGroup's opinion that the interruptible credit should be based on the amount of load that is actually interruptible at any given time?

A. (Mahmudov) I think our opinion is that it should be a verifiable number that can be -- that would be based on unstacked load. You know, if -- it should be clear that or clarified and shown to the parties that there is no overlap. So long as there is overlap

between dispatchable rider and interruptible credit, I don't think there's support for providing that credit to PHP.

Q. And in your response here, and in your response you've just given, you've indicated that there should be, I guess, proof that there's no risk of double-counting. Can you explain to me what type of evidence that would be? Like, how do you propose that be provided?

A. (Mahmudov) Well, I think that that's the challenge that we see in the Application. So the information, you know, should be able to demonstrate that dispatchable load shedding is separate from interruptible load reductions, and that's something which is lacking. I have no proposed mechanism, you know, that could be applied in this case, and we did not really focus on developing such mechanism.

So all I know is that the method should be clear and verifiable and should be able to

demonstrate to the parties that there is no overlap. Basically that the load -- can be shown that the load is stacked.

Q. Can you explain what do you mean when you say that "the load is stacked"?

A. (Mahmudov) So that NSPI could show, you know, of -- when there was a load shedding, right, it should be able to show this portion is related to dispatchable rider. And then on top of it, there is a separate load reduction that is caused by interruption -- load interruption for PHP. So that there is no overlap on that load, you know, being counted twice.

Q. And in regards to the super priority credit of 10 percent, InterGroup has relied on this Settlement Agreement terms and stating that the ELID should be approved with the premium for priority interruptibility; correct?

A. (Mahmudov) Correct.

Q. Now, would you agree with me that

there's currently no evidentiary basis for credit of that 10 percent value on the record currently?

A. (Mahmudov) Yes. And I think it's also acknowledged by NSP in the Application, and I think in the IR response as well.

Q. Just give me one moment to look over my notes.

(SHORT PAUSE)

BY MS. RUDDERHAM:

Q. Those are all my questions. Thank you so much.

THE CHAIR: Thank you.

Port Hawkesbury Paper?

MR. MacDOUGALL: Mr. Chair, we may have a few more questions than we anticipated, based on the cross-examination that just occurred. It might be better to start in the morning, unless you want to push through?

MR. MAHODY: Mr. Chair, I would just

mention as well that at least one counsel had mentioned to me that their family-related arrangements were expiring right around 5:15. So just to let you know.

THE CHAIR: Okay. Well, in that case, I think probably -- probably, yes, we will adjourn for the day and resume at 9 o'clock in the morning.

MR. MacDOUGALL: Thank you.

MR. McLAREN: Thank you.

--- Upon adjourning

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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.



Patricia Cantle
Registration No. 2017-001
ICDR, ICDT
Certificate No. IAPRT-2142

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