MAINE PUBLIC UTILITIES COMMISSION
AUGUSTA, MAINE

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| IN RE: | ) |
| | ) Docket No. 2022-152 |
| CENTRAL MAINE POWER COMPANY | ) November 10, 2022 |
| | ) |

Request for Approval of a Rate Change - 307

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CONFERENCE COMMENCED (November 10, 2022, 9:01 a.m.)

MR. BRYANT: Okay, this is the resumption of a technical conference in docket number 2022-00152, Central Maine Power Company request for approval of a rate change. Start by taking appearances first for Central Maine Power Company.

MR. DES ROSIERS: Jared des Rosiers from Pierce Atwood on behalf of Central Maine Power.

MR. DESROSIERS: Adam Desrosiers, CMP.

MR. COTA: Nathan Cota, CMP.

MR. COHEN: Peter Cohen, CMP.

MS. ANCEL: Charlotte Ancel, CMP.

MR. PURINGTON: Joe Purington, CMP.

MR. THERRIAULT: Kevin Therriault, CMP.

MS. THERRIAULT: Kerri Theriault, CMP.

MR. SADLER: Matt Sadler, CMP.

MS. BONDA-RIVA: Christina Bonda-Riva, CMP.

MR. BROWN: Art Brown, CMP.

MR. BRYANT: And as other folks come forward as maybe needed, we will make sure they enter their appearance. So for the Office of the Public Advocate, please.

MR. LANDRY: Andrew Landry for the Office of the Public Advocate.

MS. CHAMBERLIN: Susan Chamberlin, Office of the Public Advocate.

MR. BRYANT: And do you have or expect any experts to be joining remotely?

MR. LANDRY: I'm fairly sure that Lafayette Morgan will be joining.

MR. BRYANT: Okay, I see he --

MR. MORGAN: This is Lafayette Morgan on behalf of the Public Advocate.

MR. BRYANT: Good morning, Lafayette. Thank you. For Efficiency Maine Trust.

MR. BURNES: Ian Burnes with Efficiency Maine Trust.

MR. HASLETT: And Nat Haslett, Efficiency Maine Trust.

MR. BRYANT: For Conservation Law Foundation?

MR. TURNER: Phelps Turner, Conservation Law Foundation.

MR. BRYANT: I don't see anyone from Competitive Energy Services.

MR. PERKINS: Eric, this is Eben Perkins on the phone line. I'm about -- I'm coming up in person and about 15 minutes out but will be on the phone here for the next couple of minutes.

MR. BRYANT: Okay, thank you. Make sure you're on mute.

MR. PERKINS: Yeah.

MR. BRYANT: Okay. Are there any other parties present, remotely, and, if so, please identify yourself for the record?

MS. CHATTERJEE: Good morning. This is Sarah Chatterjee with Electric Power Engineers. I also have Danielle Murray and Marty Behrens with me.

MR. BRYANT: Okay. Thank you, Sarah. Those three individuals work for a consultant hired by the Commission. And for the staff, I'm Eric Bryant, one of the Hearing Examiners.

MR. BARTLETT: Phil Bartlett, chair of the Commission.

MR. SCULLY: Pat Scully, Commissioner.

MS. HEALY: Nora Healy, Hearing Examiner.

MS. TAYLOR: Daya Taylor, Hearing Examiner.

MS. HEIMGARTNER: Greta Heimgartner, analyst.

MR. MARCO: Jason Marco, analyst.

MR. SIMMONS: Michael Simmons, analyst.

MR. JOHNSON: Michael Johnson, analyst.

MR. BRYANT: And --

MR. ROLNICK: Matthew.

MR. BRYANT: Go ahead, Matthew.

MR. ROLNICK: Matthew Rolnick, analyst.

MS. PALLOZZI: Julie Pallozzi, analyst.

MR. GRUMSTRUP: Ethan Grumstrup, analyst.

MR. BRYANT: I also know that Faith Huntington is listening in by phone and may have questions. Okay. So is there anyone who needs to make an appearance who hasn't yet who might been overlooked? Okay. So the order of questioning today will begin with questions of CMP about the -- two of the five capital adjustment mechanism items, the CCI poles and the broadband poles. Staff will begin questioning. And so I'd like to turn to Michael Johnson who has a number of questions. Thank you.

MR. JOHNSON: Hi, there. This is Michael Johnson. Can everybody hear me? The 2021 updated definition of broadband by ConnectME in its rule appears impactful to joint pole owners. Please share how CMP may have participated in any of ConnectME's proceedings to relay the potential financial impact to the company, particularly around pole replacements, vis-à-vis the municipal exemption when ConnectME deliberated moving from the 25 megabits down/three megabits up standard to the hundred megabits up -- down and hundred megabits up standard.

MR. COTA: Nathan Cota. We did not actively participate in any of those proceedings. I talked with Pat in the past but nothing specific to those.

MR. JOHNSON: Okay, thanks.

MR. BRYANT: When you say you talked with Pat, Pat who?

MR. COTA: Schaffer. Peggy Schaffer, sorry.

MR. BRYANT: Okay. And Peggy Schaffer was -- is or was connected with ConnectME Authority?

MR. COTA: ConnectME, ConnectME Authority, yes.

MR. BRYANT: Thank you.

MR. JOHNSON: In Section 8 of ConnectME's rule, I think it's referred to as Chapter 101, there is a waiver provision that states, "Upon the request of any person subject to the provisions of this chapter or upon its own motion, the ConnectME Authority may, for good cause, waive any of the requirements of the of the rule." Is CMP familiar with this section of the rule and researched the possibility of exercising this provision on a case-by-case basis for the municipal exemption?

MR. COTA: I'm not familiar with it. I don't know if anyone else is. We've not explored that possibility. This is Nathan.

MR. JOHNSON: In response to OPA 3-10, Examiners 9-105, and on page 56 of the capital investment panel, the company anticipates approximately 2,500 poles or three and a half percent of the road miles identified in the connecting broadband plan that are inside CMP's territory that could be required to be replaced due to the broadband initiative. Has CMP engaged in communications with one or more municipalities about their plans for municipal broadband that would precipitate pole replacements? , please explain also explain if any municipalities seeking to offer broadband have already received pole attachment licenses from the Commission. Yeah.

Thanks.

MR. DES ROSIERS: I object to form and ask that that be broken up into separate questions.

MR. BRYANT: Yeah, let's start with the first question so -- yeah, so can you start over, Michael?

MR. JOHNSON: Sure.

MR. BRYANT: You don't need to recite the data responses --

MR. JOHNSON: Okay, yeah. Has CMP engaged in communications with one or more municipalities about their plans for municipal broadband that would participate -- precipitate pole replacements?

MR. COTA: This is Nathan. Let me just clarify. Would this be under the Maine connectivity authority funding or are you just asking a general question?

MR. JOHNSON: I'm asking in regards to any municipal broadband, you know, utility district or town that is looking at basically entering into the broadband, competitive broadband, marketplace and may need pole replacements as part of their initiative and which could trigger CMP or CCI or somebody else to replace those poles.

MR. COTA: Sure, this is Nathan. So we have existing agreements with the town of Georgetown and the town of Arrowsic. They are -- I think Georgetown is pretty much through their project now and Arrowsic's halfway, threequarters. So we've got that. Also working on an agreement with the town of Leeds and nothing formalized yet, but I am in discussions with some representatives from Waldo broadband about an upcoming project. I think that covers most of what we've seen so far from municipalities.

MR. JOHNSON: And for those first municipalities you mentioned, were poles replaced that CMP's expense?

MR. COTA: This is Nathan. Yes, at both CMP and CCI's expense.

MR. JOHNSON: And did I hear correctly there's maybe two or three towns sort of forecasted right now that might require pole replacements?

MR. COTA: This is Nathan. Yes, Waldo -- the Waldo broadband utility district is five or six towns combining into one.

MR. JOHNSON: And I have this question later, but yeah, I feel like it's a good place to ask it now. When a municipality approaches CMP for, you know -- about, you know, doing municipal broadband, is CMP required to replace those poles right now under everyone's interpretation of the statute and rule if the municipality does not have the -- you know, based on other competitive providers in the area, are they required to replace those poles if it's in the CMP service territory but not in the CMP maintenance area?

MR. COTA: This is Nathan. I think what you're asking is would the agreement with CCI possibly impact any make-ready pole changeouts.

MR. JOHNSON: That's right.

MR. COTA: The agreement -- the 2019 agreement does not cover make-ready work. So it would depend on the maintenance area who would be setting those poles.

MR. JOHNSON: So in the entire CMP service area which is expansive, right, there -- the way we -- I think we all understand it, right, there's -- the entire CMP service area, but within the -- those service areas -- within that general service area, CMP is required, through the maintenance agreements, to maintain poles and take care of things if there's a car accident, and CCI is also required to maintain in their service area. If a municipality -- and I'm just -- I don't know off top of my head, but if a municipality -- and Waldoboro, just Waldoboro itself, is in CCI's maintenance area and they need a pole replaced that meet -- that -- based on the ConnectME rule, would -- and -- but CMP is also inside that service area, would CMP have to pay for the make ready to replace the pole in that area?

MR. COTA: This is Nathan. We would not. We would pay for any transfers or other make-ready work that might be required, but the pole replacement would not. The town of Arrowsic is a good example there. Inside CCI -- it's a CCI-maintained area.

MR. JOHNSON: And there are the maintenance areas as we've talked about, and there are solely-owned poles by CMP, there are solely-owned poles by CCI. Then there are also jointly-owned poles. How are jointly-owned poles impacted in all this?

MR. COTA: This is Nathan. Jointly-owned poles are still subject to a maintenance agreement -- or by maintenance areas. And so the maintaining party would change that pole and bill the other party, the other joint owner, for the -- that replacement, the half cost of that.

MR. JOHNSON: So if there is a jointly-owned pole by CMP and CCI, but it's located inside a CCI maintenance area and at a municipality needs a pole replaced to meet the municipal exemption, would CMP be required to pay for any of the costs of that pole if it's a jointly-owned pole?

MR. COTA: This is Nathan. If CCI billed us for that pole replacement, we would pay.

MR. JOHNSON: And what would happen if there was a pole in the CMP maintenance area that is jointly owned by CCI and CMP and the municipal exemption is invoked? Would CMP have the ability to recover costs from CCI for that pole that is replaced?

MR. COTA: This is Nathan. I would anticipate -- we haven't run into that scenario yet, but I would anticipate we would still continue to bill CCI for that. We just would --

any billable make ready that -- or any make ready that we would have normally billed to the attacher would not go to the attacher.

MR. JOHNSON: Because of that is not part of the amended pole attachment -- pole owner agreement, right?

MR. COTA: Correct.

MR. JOHNSON: Okay. Thanks. This this may be an oral data request just because it's kind of on the spot here, but can CMP provide information about any poles that it has replaced either for the municipal exemption to date and by town? And then also poles it has replaced as part of the police powers portion of Chapter 880 and also its pole agreement rule.

MR. COTA: Could we clarify possibly with a time --

MR. JOHNSON: Oh, sure, yeah, in the -- I have it written down, sorry. In the last five years.

MR. COTA: In the last five years?

MR. JOHNSON: Yeah, yeah. So police powers and municipal broadband exemption in the last five years by town.

MR. BRYANT: And so that's the -- do you have that, Daya? Oh, okay. What are we -- what question are we starting with this morning?

MS. TAYLOR: Twenty-five.

MR. BRYANT: Okay.

MR. JOHNSON: So this kind of dovetails again on the municipal broadband area. In its testimony and previously kind of mentioned here, CMP mentioned that, you know, 90 percent of the state, based on ConnectME's broadband report, would qualify as either unserved or underserved and could precipitate pole replacements as part of the municipal exemption. I think I have that correct. At the same time, though, another big provider in the state, Consolidated Communications, also CCI, is in the process of doing a massive fiber overlay all over the state. And according to press reports from the company, they will be able to pass by 150,000 households by the end of the year with speeds of a gigabyte down and a gigabyte up that would far exceed the ConnectME requirements and possibly negate a big part of that map that ConnectME has previously put out. Has CMP engaged with CCI, Consolidated, about their new fidium service and how that could impact, you know, proposed municipal broadband efforts?

MR. COTA: This is Nathan. We -- I have talked with some of the folks at CCI about what they're doing because they're over lashing on poles typically that they already have equipment on. So we're not being notified in many cases of their attachment, in a new attachment.

MR. JOHNSON: Right.

MR. COTA: So we've talked generally about that but not specific to -- I don't think the level of detail that you're (indiscernible) I think.

MR. JOHNSON: Since you brought it up as well, it's another question I have here about over lashing. Just in case anyone is not familiar with that, that is the ability of a provider to just simply attach to its existing facilities on the pole. And this is, you know, a benefit to Consolidated because it has copper and fiber all around the state. So it is using this practice to quickly get onto poles. In the case of municipalities and any possible pole replacements that they may require for broadband or for police powers, has CMP studied or worked on or looked into the idea of exercising over lashing for municipal broadband purposes on existing town fiber facilities to save on cost or boxing or bracketing or other things like that that are eligible to do under our Chapter 880 rules?

MR. COTA: This is Nathan. There's very few towns that have any significant infrastructure on the poles as far as communication or fire alarms or anything like that. So it would be a very small impact. And obviously we don't allow, per the rules, over lashing on someone else's equipment. So it hasn't come up yet, but if it was possible, it would be allowed under the rules that we have today.

MR. JOHNSON: And just as a follow up for something like boxing, is there a way -- is it possible for CMP to quantify the cost of that versus a pole replacement if loading and things like that are -- if the pole can handle additional strands of fiber for the municipal broadband project? Would it -- would there be, like, a cost benefit analysis, that it would be cheaper to recommend boxing instead of a pole replacement to allow for another attacher on?

MR. COTA: This is Nathan. I don't think we've done any cost benefit analysis, and utilities are boxing as need be to avoid make ready. I would say that they don't like to do it either because it makes it hard for them to run their equipment. So it's something that's only used to avoid a costly pole change out.

MR. JOHNSON: Right.

MR. BRYANT: Nathan, could you briefly explain what boxing is?

MR. COTA: Boxing would be placing -- normally, all of the attachments are placed on the road side of the pole for ease of access and maintenance. And boxing is just allowing somebody to -- allowing a company to attach on the back side of the pole, the field side because there's typically space on that side of --

MR. BRYANT: So you're boxing the pole?

MR. COTA: It means boxing the pole. It creates some -- it can create some difficulties in maintenance later because when you set a pole, you kind of have to weave it up through. Normally you set it on the back side and kind of bring it forward, and boxing can make it difficult to change a pole.

MR. JOHNSON: And you can clarify, though, that it is allowed by the National Electric Safety Code and it is also allowed by Chapter 880 rules. Is that right?

MR. COTA: Chapter 880 prohibits us from a blanket prohibition. So we still work with our attachment partners to try to limit those circumstances, but we do allow those.

MR. JOHNSON: And one other thing I just want to mention too, addition to those things, there is also placing an attached underneath the bottom attacher. Traditionally the bottom attacher was the incumbent ILEC which, in most cases, is CCI, but there is often space available underneath that ILEC. And so there's like one more spot sometimes that's available. Let's see here. In Examiner 6-10 -- yeah, in Examiner 6-10 CMP provided a map of the maintenance areas -- actually, I'm sorry, I've already asked that. I jumped in on that one. Sorry about that. Yeah, go ahead, Jason. Jason, jump in --

MR. MARCO: This is Jason Marco. Going back to the question Michael asked about CCI and their broadband expansion, I think what we're trying to get at is under the unserved and underserved definition of ConnectME, that that's really the driver for the municipal exemption. Do you -- would you agree that that could be the driver, that the speeds, the up and down speeds, are what really where you've -- CMP's obligations to attach the pole falls in?

MR. COTA: This is Nathan. As far as the municipal exemption, it is -- it's, as far as I know, solely based on the unserved, underserved definition that the Maine Connectivity Authority, ConnectME Authority has established.

MR. MARCO: Okay. So based off of that interpretation, would you -- has CMP done any independent analysis separate from ConnectME that is for their own benefit, right, or for CMP's benefit of what speeds are offered in those potential expansion areas?

MR. COTA: This is Nathan. We would have the same information, basically the ConnectME speed map. It has its flaws, but it's basically what everybody's working off. We would have the same --

MR. MARCO: You'd use their map as --

MR. COTA: We would use their information, yeah.

MR. MARCO: Okay. So if a service provider was in the area and they were offering speeds that exceeded the served or underserved area definitions, would that exempt CMP from the municipal exception, even though the map may not provide the same data?

MR. COTA: This is Nathan. Yes. So we would expect the party invoking the municipal exemption to prove their eligibility for that exemption.

MR. MARCO: Okay, great. Thank you.

MR. JOHNSON: This is Michael Johnson again. According to Examiners 6-34 CMP currently collects pole attachment rental fees on 426,685 poles. Do your pole attachment revenues increase at all if CMP becomes the sole pole owner?

MR. COTA: This is Nathan. Yes, it would, if it became -- if you're asking if it changed from a joint owned to a soul owned, yeah, there would be an increase in our revenue from it.

MR. JOHNSON: And actually that's the next part of my question. If -- is there a difference in pole rental fees if you are the sole owner or if it's a jointly-owned pole, are the fees different? Like, the -- do you get, like, half the revenue if you share the pole?

MR. COTA: So there's a data response here. I think we laid out the rates over the last few years, but essentially to answer your question, yes. So if it's a hundred percent CMP pole, we would -- or the FCC calculation -- we would charge a hundred percent of that. If it's a jointly-owned pole, we would essentially cut that rate in half.

MR. JOHNSON: Okay. And on that note, the -- if -- you know, there's a lot of talk about the poles to be replaced as part of the CCI or the broadband project. It looked like, in OPA 3-5, that the forecasted revenues for pole rental fees was actually going to be lower. At the same time, if you look back at the 2021 to 2020 -- 2020 to 2021 review of revenues, it went up. Can you explain why -- like, if you kind of play it all out, if there are going to be more -- if CMP is going to be assuming more attachers which should, in theory, increase revenues, why the forecast, at least from OPA 3-5, looks lower?

MR. COTA: Sure, this is Nathan. I can explain that. It's hard for us to anticipate two factors when we forecast. We don't know exactly how many attachments we're going to add, and the calculation that we use for those pole attachments change every year. So that's why you've seen the forecast decrease. We had a higher cost or a higher fee 2022. It will be going down about 15 to 20 percent in 2023. And so what we have done is just kind of stick with what we know we have for attachments and apply the rate as we know it today (indiscernible) what the future it may hold.

MR. JOHNSON: In Examiners 9-11 CMP provided a list of 65,535 poles that are over 60 years old by maintenance owner. The company reported in the spreadsheet that it provided that there are 17,067 poles that are a total of, you know, no poles or in CCI's maintenance area. So those would be ones that CCI, I think, would be responsible for. However, the company also provided GIS data for all this. It provided the maintenance areas and then also all the 65,000 poles that it provided. And when you apply that on the map using the GIS data, there are actually only 11,298 poles that appear inside the CCI footprint, their maintenance area. And so there becomes a difference of 5,769 poles based on this analysis.

Can you explain -- of course you haven't seen that, but can you explain why -- when you, you know, put those poles on a map, why some of them that are -- if some of them are CCI poles appear also in the CMP footprint?

MR. COTA: This is Nathan. I can explain that. So there's been a number of agreements over the years between CMP and CCI as far as maintenance areas. In 2013, there was an agreement that swapped some towns. It did not -- there was not a wholesale change of ownership accompanying those swap -- that swap of maintenance areas. So there are 100 percent CCI-owned poles within CMP's maintenance area. If that pole requires maintenance in the future, CMP would be responsible for that and then would assume ownership of that pole. So I think that's why you see CCI poles scattered really throughout the whole territory.

MR. JOHNSON: Okay, okay. Is there -- yeah, is there a chance you can provide any more information on that as an oral data request just so we can better understand that?

MR. COTA: What would you be looking for?

MR. JOHNSON: Well, I -- you know, when you -- again, when you take all those poles and throw them on the map, it's just, like, all over the place. So the idea of the maintenance areas where you have these town by town doesn't seem to really make sense when you see all these poles all over the place just scattered everywhere on the map. You know, there's -- you know, that's, you know, almost 6,000 poles that -- out of the, you know, 17,000 or so. And so I'm just wondering if there's anymore information you can provide about that to better explain that. So --

MR. COTA: Okay.

MS. TAYLOR: So you're just looking for an -- like, an explanation about the change in the maintenance territories?

MR. JOHNSON: Right, because the towns -- there's a series of towns listed where one is one, one is the other, but now this explanation suggests that it's more fluid.

MS. TAYLOR: Okay, thank you.

MR. JOHNSON: So I'm better understanding that and how that works and where it might have happened. So --

MR. BRYANT: So, Nathan, you understand the question and --

MR. DES ROSIERS: If I may, let me try what I think the question is just so we are all square on it. Please provide information explaining why there are a hundred percent CCI-owned poles located within CMP's maintenance territories -- maintenance areas.

MR. JOHNSON: Yeah, I think that is probably accurate. Yeah, let's go with that.

MR. BRYANT: Thank you.

MR. JOHNSON: As a follow up to page 26 of the electric -- electricity operations panel testimony, CMP points out that there are 9,451 CCI poles evaluated to be DLI2 and DLI3 status that need replacing in future years. Can you provide more information to -- and I think this would have to be in GIS format -- to show us where those poles are? You know, you provided the 60-year-old poles, and there were, like, 17,000 of those. And what I'm looking to see how many DLI2, DLI3 poles are -- of those CCI's are -- like, see where they overlap, see how many of those are the 60-year-old poles and to see where they drop. So can you provide in GIS format where those 9,451 poles are?

MR. DESROSIERS: This is Adam Desrosiers. Yes, we do have those mapped on GIS, and we can provide that.

MR. JOHNSON: Okay. Perfect. Thank you.

MR. BRYANT: So the purpose of the ODR, the reference is to page EOP 26, lines two and three. Thank you.

MR. DESROSIERS: And just to clarify, that's of the known CCI-owned poles that require replacement due to the DLI program?

MR. JOHNSON: Exactly.

MR. DESROSIERS: Okay.

MR. JOHNSON: So in Examiners 6-10 CMP shared its joint pole and underground agreement with CCI that allows CMP to replace CCI poles. Did CCI explore the -- I'm sorry, did CMP explore other options to take ownership of CCI-owned or jointly-owned poles rather than only taking ownership and replacing the failing poles?

MR. PURINGTON: This is Joe Purington. I can speak to that. So since my return back to Central Maine Power, I have had conversations with CCI about an acquisition of their assets. They are not interested.

MR. JOHNSON: And as a follow up to that, can CMP share how its parent company affiliate Avangrid and its other electric utility affiliates handle utility pole ownership in other states and if ILECs are joint pole owners in those states?

MR. COTA: This is Nathan. I believe we can give you a general overview of how Connecticut in New York would work to take that as a data (indiscernible).

MS. TAYLOR: Can you, please clarify the ODR?

MR. JOHNSON: Yes. Please share how CMP's parent company Avangrid and its electric utility affiliates handle utility pole ownership in other states and if ILECs or joint pole owners.

MS. TAYLOR: Thank you.

MR. PURINGTON: So this Joe again. So I can answer it from my previous experience with other New England states and companies. Same process. This joint ownership.

MR. JOHNSON: Joint ownership?

MR. PURINGTON: Yeah.

MR. JOHNSON: And can you also answer if the electric utilities in those states are experiencing the same issues with pole ownership?

MR. PURINGTON: Without question, yes.

MR. JOHNSON: Okay.

MR. BRYANT: So does that answer -- does that obviate the need for the ODR? Because your response, Joe, was about other New England utilities, not necessarily your affiliates.

MR. PURINGTON: Exactly, yeah. I --

MR. BRYANT: You can't speak to the affiliates, is that correct?

MR. PURINGTON: I cannot.

MR. BRYANT: Okay, let's leave the ODR then.

MR. JOHNSON: Yeah, okay. I think that's all I have for now. Jason, I don't know if you have any other --

MR. MARCO: Yeah, I'd like to follow up on the -- CMP approaching CCI on acquiring their assets. My understanding of the amended -- 2019 amended document is -- or agreement is that that's exactly what is happening, that CMP is taking over the asset. Well, I guess the asset gets taken out of service when CMP replaces it, but CCI no longer owns that pole that was in that place. Is that correct?

MR. PURINGTON: That's correct.

MR. MARCO: So it's happening by attrition rather than wholesale acquisition. Is that correct?

MR. PURINGTON: That's correct.

MR. MARCO: Has -- in the -- in that amendment, there is a provision for CCI to purchase one-half interest back -- of that ownership interest back in that pole that was replaced. Was any -- in a DR, was there any response to that? There's notice that CMP or CCI has to provide. I didn't see that in a DR response. Is -- what exists on that, the notice, and how does that acquisition or option get exercised by CCI? Does CMP have any information on that?

MR. COTA: This is Nathan. I can provide you some general information. Every time a pole is replaced or added to the system, there's what's called an exchange of notice that occurs between CMP and the -- CCI or any other telephone company in the state in our territory. And that is essentially our proposal -- or CCI can send it to us as their proposal for ownership interest in those poles. So if -- in the example you're saying, if CCI -- if CMP replaced the pole, took over ownership under the 2019 agreement, CCI was interested in purchasing back the half ownership, they would send us an exchange of notice which we would have to review, accept, deny, or modify as it may be.

MR. MARCO: Okay. At what cost or what rate? Would that be determined at that time that that exchange of notice was exercised?

MR. COTA: That's -- this is Nate. Yes. So there's a fee schedule or a pole cost schedule that CMP and CCI operate under for half ownership cost. So it would just fall under that.

MR. MARCO: Thank you.

MR. BRYANT: (Indiscernible) follow-up question. Do you or does anyone at CMP track the number of pole attachment licenses that get issued annually by the Commission?

MR. COTA: This is Nate. I do keep an eye on the Commission website. I look at the Commission website every once in a while to see who's been licensed, yes.

MR. BRYANT: Do you have a sense of how many such licenses have been issued in the last couple of years?

MR. COTA: Ten. Eight to ten I think.

MR. BRYANT: Okay. Thanks. And then a question about a statement made in the capital investment testimony. If you could turn to page 52 of that testimony. It has to do with those CCI-owned poles and the company's proposal to use the capital adjustment mechanism. So in the first full question -- the first paragraph answering the first full question on that page, towards the bottom it says that "CCI pole replacements are a necessary but incremental capital investment that's easily tracked." I think that's probably true. The next sentence, however, says "Using a capital adjustment mechanism" -- in other words, the tracker -- "ensures that customers only pay for those CCI poles that CMP actually replaces." I'm not sure I understand what that means. It sounds to me like if we didn't use the capital tracker, that CMP customers would pay for poles that it didn't replace. So I need some clarification on that, please.

MR. COHEN: So this is Peter Cohen. I'll start. I think what that is saying is that a tracker would be exactly what was spent. The alternative would be a forecast that was put into the revenue requirement, and the actuals, of course, may, and likely, would differ from the forecast.

MR. BRYANT: Forecasts being forecasts.

MR. COHEN: Forecasts being forecasts.

MR. BRYANT: Okay, hold on. Let me ask other staff members if there's any follow ups on the questions that have been asked about the CCI poles and the broadband or if any Commissioners have questions about that.

MR. MARCO: Yeah. I just have one more quick follow up, and I think it goes to a point maybe Chair Bartlett was making yesterday morning. In response to Examiners 6-11 it states that CCI is not going to replace pole -- or sorry, if CCI is not going to replace poles that have failed inspection, the responsibility falls to CMP. And I think it was just said yesterday that CMP ratepayers wouldn't be responsible for CCI's failure to replace those poles. Is there a remedy in these management contract -- management agreements that CMP has with CCI to sort of enforce CCI to do its duty?

MR. DESROSIERS: This is Adam Desrosiers. There's not one that I'm aware of. It would be extremely helpful if there was because we wouldn't be in this situation.

MR. MARCO: Thank you.

MR. DES ROSIERS: I might suggest it's in Title 35-A.

MR. PURINGTON: This is Joe Purington again. So I would say that's a New England issue with the company and it's not just a Maine issue.

MR. BRYANT: Were any of the witnesses here today involved in the negotiations with CCI when the 2019 amendment to the agreement was made?

MR. PURINGTON: I was not.

MALE: No.

MALE: No.

MR. COHEN: This is Peter. No.

MR. BRYANT: Okay, thanks.

MS. TAYLOR: I have one follow up. Nate, you referred to a fee schedule a few minutes ago that you have with CCI when CCI wants to buy back part of their joint-ownership pole. Could you, please provide a copy of that fee schedule?

MR. COTA: Yes, we can (indiscernible).

MS. TAYLOR: Thank you.

MR. DES ROSIERS: Twenty-nine?

MR. BARTLETT: How often does CCI exercise that option to buy half back?

MR. COTA: I've been in this -- this is Nate. I've been in this role three plus years. I have not seen that done yet.

MR. PURINGTON: This is Joe. I would just add I don't think they have an intention to go back into the pole maintenance business because it's not part of their business model, at least in my conversations with executive-level people at CCI. So I think you're seeing the movement across New England to kind of force us, especially when they're not regulated.

MR. BRYANT: Okay, I believe we're done with staff questions on this issue. Let me turn to the OPA and ask the OPA if it has any questions on follow up.

MS. CHAMBERLIN: Well, I have a series of questions in general on pole attachments. Can I just go ahead with those?

MR. BRYANT: Yeah, sure. Thanks.

MS. CHAMBERLIN: Okay. I'm looking at page EOP 38. It's Figure 12. And is this a figure for the unserved and underserved areas only?

MR. COTA: This is Nate. This would not be specific unserved or underserved. It would be our anticipated pole attachment requests across the system.

MS. CHAMBERLIN: And I think I just heard 90 percent of that is the unserved area. Is that correct?

MR. COTA: This is Nate. Since the definition was changed from 25 over three to a hundred over a hundred, I think essentially almost all of the state of Maine falls into unserved or underserved categories.

MS. CHAMBERLIN: And because of this being an unserved area, would the attachment rate be single occupancy almost always?

MR. COTA: This is Nate. So the occupancy of the pole, are you saying sole ownership or joint ownership?

MS. CHAMBERLIN: Yes, single versus joint.

MR. COTA: So it would -- can you repeat the question so I'm sure I have it?

MS. CHAMBERLIN: Would you agree the pole attachment rate applicable would be for single occupancy versus joint?

MR. COTA: I would not agree with that. There are areas of the state which continue to be joint owned, and any joint-owned poles there would be applicable to the joint-owned pole attachment rate.

MS. CHAMBERLIN: Do you have any sense of the percentage?

MR. COTA: This is Nate. The percentage of joint owned versus sole owned, I think we've got some numbers here somewhere, but joint-owned poles, I think, are around 130,000. That's out of a total population of 600,000, 660,000 approximately, total poles.

MS. CHAMBERLIN: And reflecting the chart, it talks about pole attachment applications. Is that one attachment per application?

MR. COTA: This would be -- this is Nate. This would be the number of poles, not necessarily the number of applications. Sometimes we cross those terms over, but this chart is showing the number of poles we anticipate attachment requests for.

MS. CHAMBERLIN: So this does not reflect at all the number of attachments?

MR. COTA: This is Nate. We would anticipate -- this chart is showing the number of poles which would equate to the number of attachments. Each pole would have one attachment request typically.

MS. CHAMBERLIN: One attachment per --

MR. COTA: Yes.

MS. CHAMBERLIN: And is it an estimate for all types of attachers, CLEC, CATV, private municipal, anybody?

MR. COTA: This is Nate. That's correct.

MS. CHAMBERLIN: Okay. And is there a document that breaks down these projections as to the type of attachers?

MR. COTA: We do not have a breakdown. It's just based on the -- it was based on the number of miles, the poles we thought would be involved, and it's just a straight across estimate that way.

MS. CHAMBERLIN: Okay. So an ODR won't help. You just don't have that information.

MR. COTA: I do not have that information.

MR. COTA: I would say the definitions of CLEC, cable TV, private are becoming fuzzier than they used to be. So 20 to 25 years ago there was a big difference between a CLEC -- it was basically just cable TV. All of these companies are now offering the same services, and they're an attachment on a pole. So we still split it out sometimes just for historical perspectives and what not, but really an attachment today is an attachment. And there's not as much emphasis put on CLEC versus cable TV. CLEC versus ILEC or cable TV versus ILEC, there's a difference, but as far as any competitive service, it's an attachment on (indiscernible).

MS. CHAMBERLIN: And are the rates charged the same?

MR. COTA: For cable TV, CLEC, yes, they would be the same rates.

MS. CHAMBERLIN: And on page 37 it states roughly seven percent of all poles require some construction work (indiscernible) accommodate attachments. And is that a reference to make-ready work?

MR. COTA: This is Nate. Yes, that would be in reference to make-ready work.

MS. CHAMBERLIN: And what are the rates that apply for make-ready work?

MR. COTA: The rates that would apply for make-ready work would be an estimate provided by CMP to the customer.

MS. CHAMBERLIN: It's an individual assessment, each attachment?

MR. COTA: Yes.

MS. CHAMBERLIN: And so who is billed, the attaching company? Is that correct?

MR. COTA: There can be both billable and non-billable work included in that seven percent number.

MS. CHAMBERLIN: And why is that?

MR. COTA: Some poles that are applied for could already be -- there could be several reasons. One could be it's already been identified as part of the DLI program for replacement. We would not charge a new attaching customer to replace pole that we had already identified. Sometimes there are existing clearance violations or inadequacies on the pole that would -- we'd not charge the customer to remedy.

MS. CHAMBERLIN: Do you have a revenue projections for make-ready work?

MR. COTA: I do not have any make-ready revenue projections? No.

MS. CHAMBERLIN: Does anyone? Does the company keep that or make that projection?

MR. COTA: I'm not aware of any projections.

MR. MARCO: Susan? Susan, this is Jason. Can I ask a quick follow up on that? Do you break out historical make-ready work?

MR. COTA: We --

MR. MARCO: -- as a line item on a revenue statement?

MR. COTA: That would be a question from Peter maybe or somebody who can answer it how that revenue works, but any billable make ready that comes into the company is applied as revenue somewhere. You can help me out.

MR. COHEN: Sure.

MR. DESROSIERS: Yeah, I believe Peter's checking with the revenue requirements panel.

MR. MARCO: Thank you.

MR. BRYANT: Do you have other questions that you can pose while we're waiting?

MS. CHAMBERLIN: Sure.

MR. BRYANT: That'd be great. Thanks.

MS. CHAMBERLIN: OPA 3-6, Attachment 1, and it's -- the first tab is revenue by entity. And the totals for the test year revenue for pole attachments is 12.9 million. Are you on the --

MR. COTA: Okay, somebody from revenue is here so --

MS. CHAMBERLIN: All right, (indiscernible) question.

MR. HURWITZ: This is Jacob Hurwitz. Could you, please repeat the reference? I'm sorry.

MS. CHAMBERLIN: I was asking about revenue projections from make-ready work and the page in the testimony, page 37, line 21 says roughly seven percent of all poles require some construction work which is make-ready work. And I'm asking are revenues projected into the future?

MR. HURWITZ: This is Jacob Hurwitz. I can speak to what's reflected in revenue requirement, not what anyone else in the company may have prepared. Within the revenue requirement model, there is a line called pole attachment. It includes the number you referenced, approximately 12.97 million. We escalate that at the general rate of inflation, and as we described in response to a data request, we do apply a specific discrete increase in the expectation for these revenues which is tied to an expected cost increase on another schedule.

MS. CHAMBERLIN: Okay, I think that's a separate question. There's revenue for pole attachments and revenue for make work. Is at the same thing?

MR. HURWITZ: I'm not sure.

MS. CHAMBERLIN: I don't think it is.

MR. COHEN: This is Peter Cohen. So in the revenue requirements schedules, we don't have unlimited, you know, categorization. So it would be my belief that make-ready work would be included in the pole attachment line. We can obviously verify that via an ODR and --

MS. CHAMBERLIN: Okay, that would be helpful.

MR. COHEN: -- provide a complete response.

MS. CHAMBERLIN: So the ODRs is revenue projections for make-ready work separated out from any revenue projections for pole attachments. And just continuing on the Attachment 1 questions, we're looking at revenue by entity, and all the amounts are credit balances except one which is a debit balance. That's on line 51. And it appears to be just debit balance for about $1 million. Is -- do you have that line?

MS. HEALY: While you're looking for that, can I ask -- or add to Susan Chamberlin's ODR as well? I'd like to understand the revenue projections for the pole attachment -- all pole attachment fees, including make ready, through the three rate-effective years and whether they were -- I understood from the conversation that they were escalated for an inflation rate and also offset by some increases in costs. But what I'm trying to understand is were they escalated to reflect the predictions about full attachments shown in Table -- whatever it was, Figure 12.

MR. BRYANT: Figure 12.

MS. HEALY: Figure 12 on page EOP 38.

MR. DES ROSIERS: While they're looking, I can say that the whole idea of them being covered by a tracker is that they are not reflected in the revenue requirement to the extent they are incremental pole attachment resulting from the broadband. So it's --

MS. HEALY: Either costs or revenues?

MR. DES ROSIERS: Correct. All of that was going to be put in the tracker for the broadband program for -- to really track both the revenue and the cost distinct from other pole attachment revenues that could be -- could grow from other -- obviously other poles or other --

MS. HEALY: Then I don't think I need my -- thank you.

MS. CHAMBERLIN: Okay, are we ready? We've got OPA 3-6, Attachment 1?

MR. COHEN: This is Peter. I'm ready.

MS. CHAMBERLIN: Great. And I'm looking at I believe it's line 51, and there's a line showing a debit balance of about $1 million. Can you describe the transaction which would create this debit balance?

MR. COHEN: So this appears to be -- I've not. I did not prepare this response, but this appears to be a list by vendor of payments to CMP. This is obviously going in the opposite direction (indiscernible) this was a payment.

MS. CHAMBERLIN: Right.

MR. COHEN: I can't speak to what market sales ACC is, but if you'd like, we can take an oral data request (indiscernible) give you background into that.

MS. CHAMBERLIN: Yes, we want to know what the transaction which created the debit balance was about and is it a normal or recurring transaction.

MR. COHEN: Sure.

MS. TAYLOR: Can you, please -- can I have the DR reference again, please?

MS. CHAMBERLIN: It's OPA 3-6, Attachment 1.

MS. TAYLOR: Thank you.

MS. CHAMBERLIN: All right, now I'm looking at OPA 3-2, comparing it to OPA 3-4. And when you look at these numbers together, it appears that the number of poles remain roughly the same over several years in spite of a substantial number of CCI joint pole replacements. So OPA 3-2 talks about CCI-owned joint-use poles being replaced, and then 3-4 just talks about pole counts. And it appears that those two have not been correlated. And we would ask that the pole counts be updated. If our theory is correct, and if it's some other reason, we'd ask for an explanation.

MR. COTA: This is Nate. I think we'll have to take that as an ODR.

MS. TAYLOR: Can you, please repeat the ODR?

MS. CHAMBERLIN: Sure. Reference OPA 3-2 and OPA 3-4. OPA 3-4, Attachment 1 provides CMP pole counts for 2020, 2021, and 2022. The count of jointly-owned poles does not appear to decline in line with the replacements indicated in OPA 3-2. Please explain.

MS. TAYLOR: Thank you.

MS. CHAMBERLIN: And then referring to CIP testimony,

Table 9, yesterday counsel distributed updated chart. And I'm wondering (indiscernible) explain what -- why there was a need for an updated chart. Is all the data out of the original Table 9 -- can no longer refer to that or what caused there to be the need for a new chart?

MR. DESROSIERS: So this is Adam Desrosiers. The main differences on Table 9 was really consolidation of the poles replaced by the DLI program and other column into one column and then adjustment of the cost per pole for replacement using what we had historically paid per pole for 2019 through 2021 and then adjusting the per-pole cost for the installation construction component through 2022 through 2026.

MS. CHAMBERLIN: So is it fair to say -- I'm looking -- OPA 3-2 says there are about 70,950 CCI-owned joint-use poles in CMP's service territory. Is it fair to say that the pole replacement program will replace about 40 percent of the CCI-owned joint poles?

MR. DESROSIERS: What was that data request again?

MS. CHAMBERLIN: It was -- I'm just asking for the percentage of replacements. So will the proposed CCI pole replacement program replace about 40 percent of the CCI-owned joint pole?

MR. DESROSIERS: So looking at the revised total of poles that we anticipate needing replacement on the adjusted Table 9 of about 27,000, I believe one of the tables we just looked at showed around a hundred and -- what's the total? I guess what I'm getting to is I would foresee it being much less than 40 percent of their poles being replaced as part of the DLI program.

MS. CHAMBERLIN: Then as an ODR could you give me what percentage (indiscernible) and how you calculate it?

MR. DES ROSIERS: Over what time period? As reflected in Table 9, the years included in the --

MS. CHAMBERLIN: As reflected in Table 9. So 2019, 2020, 2021.

MR. DESROSIERS: So basically forecasting out the percentage of the joint-owned poles that we would expect to replace through just the DLI program or whatever is applicable to the amended CCI agreement, because there is poles that CCI still responsible for replacing outside of that agreement. So you're talking anything that would be replaced that's applicable to that agreement?

MS. CHAMBERLIN: Yeah, I -- we're referring to the CCI pole replacement program. So whatever is (indiscernible). And then turning to CIP 56 discusses pole replacements for the broadband initiative. And CMP estimates the need to replace over 10,000 poles through 2026. And I was looking for an -- how did you come up with that estimate?

MR. COTA: This is Nate. We -- I don't have the data response right in front of me, but we took the 2020 ConnectME broadband action plan and used the approximately 17,000 miles that they determined in that plan as unserved or underserved, assumed 50 percent of those miles were within CMP's service territory, applied the historical percentage of make-ready pole replacements to that number of poles that that would entail, and forecasted that over a number of years. And that's kind of -- that's basically how we came up with the 10,000 estimate.

MS. CHAMBERLIN: Thank you. And the cost estimates go up about $4 million a year. Is that because more poles are being replaced or that the costs are escalated in some way?

MR. DESROSIERS: Sorry, this is Adam Desrosiers. Could you ask that again?

MS. CHAMBERLIN: Sure. Just as the numbers -- as the years go out, the costs increase about $4 million a year, I'm just wondering what's the basis of that increase?

MR. DESROSIERS: That's really two pieces. There's an escalation put on future year forecasts and then also the increase in the pole setting and construction cost that we highlighted as a footnote on the adjusted Table 9.

MS. CHAMBERLIN: All right, thank you. That's all I have.

MR. BRYANT: Thank you, Susan.

MR. BARTLETT: Quick question. So you made a reference a number of times to the fact that if an attacher or somebody's requesting work on a pole and if it's been identified as, by the DLI program, that that doesn't get -- that cost doesn't get passed on, is there any assessment done of whether the pole would qualify for the DLI program or is it just the DLI team hasn't seen it yet, hasn't identified it, that's just a bright line?

MR. COTA: So this is Nate. When we get an application for pole attachment, we send a surveyor out to inspect that pole. And they're looking at -- they're not really doing a DLI inspection, but they're looking at the condition of the pole, they're looking at the clearances, and it is similar to a DLI inspection. So I guess the answer to the question is we are going out and inspecting the poles. We've given our surveyors some general guidance on what is acceptable versus not, and they make a determination in the field of whether that make-ready work, if required, would be billable or non-billable (indiscernible) customer.

MR. BARTLETT: Thank you.

MR. BRYANT: Do any parties participating on Teams have questions regarding CCI poles or broadband? Hearing none, why don't we move back to the grid modernization panel.

MR. DES ROSIERS: That's fine with one -- just Greta had a question yesterday with respect to the 2022 actuals, and it was referring to EXM 09-80. And we deferred it to Mr. Desrosiers and he's here. So if we want to still ask that one, it's a good time. Otherwise, I'm happy to --

MR. BRYANT: Well, my understanding is that Mr. Desrosiers is also on the EOP panel, and we have yet to exhaust our questions on that panel. So we can do it now where we can do it -- let's do it when that panel's in place. So we'll switch to the grid mod thing, and I'm going to turn to Ian. When they're in place, Ian, you get to resume your questioning.

MR. BURNES: It's the regulatory version of a pit crew. Thanks, guys. You guys are good.

MR. BRYANT: So as we've done so far, when a new panel sits, I'd like you to identify yourself sequentially by name and, you know, at the same time, enter your appearance, your name, and your title, starting with Ms. King.

MS. KING: Good morning. Rita King.

MR. BOCHENEK: Scott Bochenek.

MR. MADER: Good morning. Jim Mader.

MR. MANNING: Bob Manning.

MR. ALONSO: Miguel Alonso.

MR. BRYANT: Okay, good morning. I remind you all that you're under oath, and I'll turn it over to Ian Burnes from Efficiency Maine Trust for questions.

MR. SULLIVAN: Sean Sullivan's here as well.

MR. BRYANT: Well, let me ask -- so you already entered an appearance, Eben. Never mind. Eben Perkins is now here in person. So go ahead, Ian.

MR. BURNES: All right, terrific. Ian Burnes from

Efficiency Maine Trust. The remaining part of my question is on your active network management program. And I'm going to start with can you explain Avangrid's relationship with Smarter Grid Solutions?

MR. MANNING: Sure. Bob Manning. So we have a project in our New York affiliate, both RG&E and NYSEG, where we're using a Smarter Grid Solutions platform to do REV, REV is reforming the energy vision, demonstration project.

MR. BURNES: And did CMP go out to bid for these services?

MR. MANNING: So no, what is -- Bob Manning. So what is proposed in the capital tracker was a representative project.

MR. BURNES: So is it fair to say that you haven't received competitive pricing for the project that you're trying to do in Maine?

MR. MANNING: Bob Manning. Correct.

MR. BURNES: So I'd like to -- I'm going to try to ask questions about the confidential attachment to 10 -- Examiners 10-47. And I recognize that the protective order refers to the terms and conditions. I'm going to try to do it in a non-confidential way. If I ask whether the terms of this are fixed cost or variable cost or subscription or not subscription, will your answers be confidential?

MR. MANNING: Bob Manning. Could you repeat the attachment that you were referencing?

MR. BURNES: So that's --

MR. BRYANT: There's two attachments to Examiners 1-10.

MR. BURNES: Yes, this is the spreadsheet.

MR. BRYANT: So that's Attachment 1.

MR. MANNING: But it's a 10-047?

MR. BURNES: That's correct. I think it's also OPA 2-24. Okay, no, I got the -- I have them both open. Yeah. Do you need me to repeat the nature of the question to determine whether it's confidential or not?

MR. MANNING: If you could, please.

MR. BURNES: If I ask whether the -- can I ask about the nature of the structure of the deal, whether -- of the service agreement, whether the -- whether there is a subscription or isn't a subscription and the nature of that subscription?

MR. MANNING: So Bob Manning. So this proposal is for a cluster area. We did provide details of the cluster area to Smarter Grid Solution, and they provided a proposal. Their proposal includes professional services and licensing for their software platform.

MR. BURNES: So I can ask about the licensing and that's not confidential?

MR. MANNING: Bob Manning. I guess it depends on your question. I think if we --

MR. BURNES: So, I mean, I don't want to reveal anything that's potentially confidential. The protective order was very broad in saying terms and conditions, and anything might be considered a term and condition. So I'm trying to understand whether everything about this relationship is confidential or whether there are ways that I can ask this. I don't want to know -- that we can -- I'm trying to avoid getting this into confidential, but I'm just trying to understand what exactly it is you don't want revealed here.

MS. KING: This is Rita King. I think, Ian, let's go ahead and have you ask your questions, and we'll flag if we think you're getting into confidential and sensitive information.

MR. BURNES: Okay. So when you have a license agreement with these as Avangrid, does that obligate you to use it in all of your service territories?

MR. MANNING: So the license agreement would be with CMP for this proposal. It is not with Avangrid.

MS. KING: And this is Rita. The arrangement we have with Smarter Grid Solutions does not obligate us to use it in all of our territories.

MR. BURNES: Well, I'm seeing an enterprise license cost on cell C5 which appears to be substantially more than any of the breakdown on an annual basis.

MR. MANNING: Bob Manning. So we did get pricing for an enterprise-wide license. That's not reflected in this proposal.

MR. BURNES: Okay.

MR. MANNING: The proposal is specific for the cluster area.

MR. BURNES: Okay, so that would be the following line of C6 for --

MR. MANNING: Bob Manning. Correct.

MR. BURNES: Is the nature of this license -- is this a -- does this permit you a number of devices or can you hook up any number of devices? Can you expand this pilot to be seven or eight or 20 or a hundred or is it limiting you in the number of the devices you can control?

MR. MANNING: This is Bob Manning. So if we went with an enterprise license, which we're not proposing in this, it's basically tiered licensing structure by number of substations. So to your point or to your question, unlimited devices. So it's not licensed per DER site.

MR. BURNES: So if -- so this is going to be per substation and then however many devices are underneath that substations are covered in the pricing that we see here?

MR. MANNING: Correct. And additional DER sites could be added in the future. And the only --

MR. BURNES: Presumably if they are under that substation, but if they're not under the substation, you're going to need to get another license?

MR. MANNING: Correct. And this cluster area covers several -- I'm not sure the exact number, but several substations.

MR. BURNES: And given -- so given the fixed number -- you know, given the fixed cost associated with the license, the more DERs that you connect, the more this the more cost effective this investment is? Cost effective in terms of the amount of benefit that you're passing on to the distributed energy resources you're connecting.

MR. MANNING: So this is Bob Manning. That part or that portion of the project we are including in the capital tracker. So those costs weren't planned to be passed on to the DER developer. This platform could be also used for other -- you know, other DERs or other applications such as managed charging. We're not planning that for this use case. This is really just for, again, the cluster area that was referenced.

MS. KING: This is Rita, and Bob's going to correct me if I'm incorrect, but my understanding is yes to your question. The more DER sites that elect to be part of the pilot, it's more cost effective for the company with respect to the investment. There is continued portions of the pilot that the contractors would be -- sorry, that the developer would be responsible for, and that's a per-site cost for the developer.

So what we're recommending here is that there is a company investment which is sort of the head-end system that would be recovered through the capital tracker mechanism, and that is a -- you know, the licensing there is also what Bob has been talking about, the tiered per substation. So the more DER sites you get, the more cost effective that licensing and head-end system investment is for ratepayers, but there continues to be a cost for developers at their site. Does that make sense?

MR. BURNES: It does, but it also opens up some other questions for me. So the -- are all of the costs associated with this subscription related?

MR. MANNING: No. So there is -- Bob Manning. So there's costs at what we're calling the grid-edge device. So the -- basically the appliance that interfaces with the DER equipment, maybe a plant controller or maybe specific inverters, and that will be -- similar to our interconnection process, that will be billed at cost and cost recovered through the DER developers. Each site may be a little different. So the cost may vary depending on site configuration.

MR. BURNES: So I'm just trying to work through in my mind here. On line 59 you have a materials line. I'm seeing a number that looks a lot -- very similar to a subscription. So there's a subscription that's included as a material and then other numbers that look -- I'm not as familiar with from a subscription perspective. So are you mixing subscription and actual devices in and calling them all materials?

MR. MANNING: Correct. So there is -- there's hardware that -- which is material, right, an appliance at the DER site, appliance at our energy control center, in the data center, firewall servers, etc. I mean, those are all considered materials. I'm not sure where you're getting this subscription --

MR. BURNES: Right, license. When you buy a license, is that good for a year or is that good for multiple years?

MR. MANNING: So the software license would be for multiple years, but then there would be potential maintenance and support costs.

MR. BURNES: Okay, that's helpful. I -- when you -- mentioned additional functionality. When you're buying this license and you're buying it, from what I understand, for a fixed -- is it a substation or is it a number of substations for this license?

MR. MANNING: It's for a number of substations.

MR. BURNES: How many?

MR. MANNING: I'd have to -- that could be an ODR. I don't have the exact number, but it's the Lakewood, Winslow cluster study area that was done.

MR. BURNES: So when you're talking about -- but part of your justification for putting it into distribution rates is that you could use it for other things later on. How many substations could you use it for later on without expanding on this license cost?

MR. MANNING: I mean, subject to check with the vendor, it would be the cluster area substation. So any incremental substations outside of the cluster area would result in additional licensing fees.

MR. BURNES: Okay. So you're -- the functionality that -- you're only ever going to be able to do this in this one individual cluster for this cost. So the total cost that we see in the bottom there is only going to be for this cluster, and any additional functionality would have to be -- we have to -- there'd be new costs associated with that?

MR. MANNING: So if there was additional functionality in the cluster area, there would be probably professional services cost to configure the system. There shouldn't be additional licensing cost I would not expect. And just to confirm, this project is a pilot. We're not looking to roll this out throughout CMP territory at this point, right? We would like to pilot the technology, the feasibility of the technology, the interest in the DER developers in adopting the technology to further growth of DER interconnections.

MR. BURNES: I'm just struggling with the distinction that you're making between charging that the DERs and not charging the DERs. So you're not charging the DERs for the license agreement, but the pilot is only for DERs. So I'm trying to understand what your justification -- what's the line there in which you say we're charging DERs for this and we're not charging DERs for that.

MR. MANNING: So Bob Manning again. So what we're proposing to charge the DER developers is any work at their site to integrate -- again, use the term grid-edge device. So the appliance at their site that integrates with either their plant controller or the specific inverters at their site. That would be charged at cost to the developers. The platform, the head-end platform, which could, again, house -- in the future host let's say a hundred substations, we were not planning to charge --

MR. BURNES: You know, you just did -- I'm sorry. I'm sorry to interrupt you there, but didn't you just say that the head-end platform and the license that you have actually could only serve this substation?

MR. MANNING: No, I said the licensing fees only cover the Winslow, Lakewood cluster area. So again, we wouldn't be putting in additional servers and firewalls, etc. That is basically a one-time cost.

MR. BURNES: But there there's a cost to the license here that you're -- that is just -- I'm just -- I'm struggling to see -- you would have to -- what are the things that you -- that -- I'm trying to figure out what are the costs -- what would expand if we were to do hundreds of substations and what are the sort of fixed costs associated with this?

MR. MANNING: Okay, Bob Manning. So, yeah, let's start with the pilot, right. So the pilot project as proposed in the capital tracker includes DER developer costs, right, which are the grid-edge equipment costs. And then it includes cost that we're looking for ratepayers to fund, and that includes the equipment in the ECC. So hardware, software, and then also licensing fees, right, and that covers the cluster area pilot. And then to your question, if we were to expand that pilot, this was a business as usual opportunity or offering, and let's say we're covering the entire CMP territory, there would be additional licensing costs to cover those additional substations. And, again, the plan --

MR. BURNES: Have you broken those categories of costs out? So when I'm looking at the total cost of this, it's 2.9 million. Have you broken those three categories -- or I'm assuming maybe the -- that doesn't include the grid-edge devices. Is that correct?

MR. MANNING: Yeah, so the 1.7 in the capital tracker -- you see that number?

MR. BURNES: Yes. Yes.

MR. MANNING: So that is planned -- or we're proposing to cover -- or those costs to be funded by CMP ratepayers. The grid-edge cost we did not estimate because that would be determined based on how many DER developers actually want to be involved in the pilot and sign up for the pilot. And also, those are site specific, the actual costs, based on the configuration of the site.

MR. BURNES: Okay, I'm -- and maybe this --

MS. KING: This is Rita. Can I just jump in for a minute? So the 1.7 that we've included as part of the pilot cost, it is for the head-end system which the ECC needs to have visibility into what the DER sites are doing. So that's -- the head-end system allows that functionality plus the cost of licensing which is tiered at a substation level. For now the substations included are the ones that Bob just mentioned for the cluster study. So we included those in this filing because we believe that all customers are going to benefit from the ability to have additional renewable generation interconnected onto the system. What we haven't included in the filing is cost for DER developers, and there is a cost for DER developers that they're going to have to incur if the pilot is to be successful and move forward. So, you know, we talk about the grid-edge cost for DER developers, but we don't -- we have not included that here. We're not looking for recovery of those costs in this filing.

MR. BURNES: So I'm trying to reconcile this direction, and something that the policy panel said yesterday that, to date, the company had not incurred any expenses as a result of the increased DER interconnection and this is a market difference. You're now saying that all of your customers are going to benefit from lowering the potential cost of interconnection and that we -- that those customers should pay for DER interconnection, lowering the cost of DER interconnection. Is that, just at a high level, policy -- acknowledgement with this pilot that you're shifting directions there?

MS. KING: This is Rita. So we're not shifting directions there. What we are saying is recognizing that the state has clean energy goals. This is an opportunity for the state and the company to work together with other stakeholders to explore the idea that other states have actually moved forward which is that all customers benefit from having these clean energy goals move forward. And so it's not a shift, it's a potential opportunity for us to consider. We've included it again in this filing in the capital tracker to get a sense of is this something that the Commission would be interested in us moving forward and thinking about and seeking alternatives to the current interconnection process that we have. So we're not changing that process unless there's a desire to do that. And so we've offered, you know, an approach and a design that's worked in other states and we believe will be attractive to DER developers. We have pilots with some data and some anecdotal information from those developers that were they not -- were it not for this type of innovative approach to interconnections, that they would not move forward with their renewable projects. And so, you know, hopefully that makes sense from a policy perspective. I don't know if others have anything to add.

MS. HEALY: May I ask a quick question here, Ian?

MR. BURNES: Yeah, please do.

MS. HEALY: For the sake of clarity, but for the DERs, would CMP propose the active network management pilot or not?

MR. MANNING: For the use case -- this is Bob Manning. For the use case at this point, this was for DER Interconnections.

MS. HEALY: Okay. So -- and as I'm understanding it, you've articulated a sort of general potential benefit to ratepayers of advancing the state's policies regarding renewable resources. But you also, I think, indicated that there's potential significant benefits for DERs individually, increases in hosting capacity and other types of benefits, that as you indicated might be attractive to DERs?

MR. MANNING: Correct.

MS. HEALY: And am I also understanding your testimony that beyond the pilot, if you are -- if this were to be determined to be successful, you would want to expand this and you would continue to promote the idea that CMP ratepayers should continue to absorb some of these costs?

MR. MANNING: Bob Manning. Correct.

MS. KING: This is Rita, and I'll add to that. I think we would have to wait and see what the results of the pilot look like before we made additional future recommendations. I think the idea here is that while the CMP cost would be fixed, the more DER sites you get to be part of a pilot, the costs continue to stay fixed and you have additional benefits at potentially, you know, nominal incremental costs.

MS. HEALY: Do you agree that at some point there are enough DERs on the system that would allow -- in combination with other, you know, things that are going on, that would allow the state to meet its clean energy goals?

MS. KING: This is Rita. I think that the experience we've had in the last couple of years with interconnection, we believe this could be an innovative short-term solution to continue to allow the DERs to -- renewable energy to integrate. At some point, yes, it's possible that there's enough that this type of approach is not necessary, and we would definitely assess that at that point. And, you know, we would seek to work with the Commission to decide when it's appropriate to stop offering this type of solution.

MS. HEALY: And has the CMP done any analysis as to what sort of level of DERs might be (indiscernible) tipping point?

MS. KING: This is Rita. No, we have not.

MS. ANCEL: This is Charlotte Ancel on behalf of CMP.

Nora, if I could just build on Rita's response. It is the policy of CMP, we understand that the regulatory rules and we support this, is that interconnecting customers, including distributed resource interconnecting customers, pay for their cost to interconnect to the system. I just want to be clear, our position on that has not changed. This is, as proposed, small pilot to test the proposition as to how we interconnect distributed resources and are there more efficient ways to do it. The company proposed it as a policy matter as a cost to be socialized among CMP customers because of the broader benefits of hitting the state's energy goals. But to be clear, this does not -- this -- inclusion of this pilot in CMP rates does not -- was not intended to represent a change to that policy of interconnecting customers bear their costs of interconnection.

MR. BRYANT: I need to step in here. It's time for a break. Ian, I hope that's okay to do that now.

MR. BURNES: Sure. I'm just about done here, Eric. Do you mind if I just -- do you want me to just wrap up so we can move on or do you need to need to break?

MR. BRYANT: Well, we do need a break.

MR. BURNES: Okay, I can come back.

MR. BRYANT: -- for a variety of reasons. You know, and I know Faith has a follow-up question as well. So it might take a little longer. Let's come back at 10:53.

MR. BURNES: Okay.

MR. BRYANT: Thanks, Ian.

CONFERENCE RECESSED (November 10, 2022, 10:37 a.m.)

CONFERENCE RESUMED (November 10, 2022, 10:53 a.m.)

MR. BRYANT: -- on the record. Looking at the list of participants participating remotely, I see that Melissa Horne has joined. Melissa, could you identify yourself for the record, please?

MS. HORNE: Good morning. Melissa Horne on behalf of Walmart.

MR. BRYANT: Thank you. Has anyone else joined who did not make an appearance earlier this morning? I don't see any names that (indiscernible) a yes to that, but -- okay. So, Ian, if it's okay, I'm going to ask Faith to ask her follow-up question and then turn it back over to you.

MR. BURNES: Absolutely.

MS. HUNTINGTON: Thank you. I just had a couple of follow-up questions on the A&M. My understanding is that this would allow distributed resources to interconnect without paying for certain network upgrades that would otherwise be required by their interconnection. Is that correct?

MR. MANNING: This is Bob Manning. Correct. So the way the technology works, this would be offered as an alternative to system modifications. So potentially, let's say, a conductor upgrade, what we would do is the system would curtail the generator if we were approaching the rating of that conductor or that asset. It could be a substation transformer or whatever type of distribution asset. So it would actually curtailed the generator not to zero, but it would still allow the generator to produce but to a level to maintain safe and reliable service.

MS. HUNTINGTON: And presumably the cost associated with this system would be less than the cost of the network upgrades that would otherwise be required to allow the project interconnect. Is that the logic?

MR. MANNING: So Bob Manning. So that would be the concept, yeah, but each project would be, you know, weighed, right. The developer makes their decision. So they would have to weigh the hours or energy curtailment versus, you know, a firm capacity upgrade, right, and make their decision on which way they wanted to go.

MS. HUNTINGTON: Okay. What then is the -- and there were some discussion earlier about the company's not changing their approach in terms of allocating cost to interconnecting projects that are driven by the fact that the project is interconnecting to the project. What is the logic then for allocating these costs to CMP ratepayers versus allocating the cost of this project to the interconnecting DERs?

MS. ANCEL: This is Charlotte Ancel. Rita, do you want to start on a response to that?

MS. KING: Sure, this is Rita King. So the logic there is there are portions of the pilot that would be recovered by CMP ratepayers because the additional renewable generation that can be interconnected is going to benefit all customers. And we have, as I mentioned before, heard from other DER developers that sometimes they will not interconnect because of the cost of system upgrades. And so this is an approach that allows a portion of the pilot cost to be recovered by customers and DER developers would still pay their share of the cost.

MS. HUNTINGTON: Has the company explored the possibility of establishing some kind of a fixed fee that would be assessed to the interconnecting DERs to recover the cost of a system like this? And just again, Rita, to respond to your comment, I'm assuming that in the context of a choice -- or a decision by a project interconnect or not interconnect that this would be a solution that would be less costly than the network upgrades that would otherwise be required. Is that not correct?

MS. KING: This is Rita. That's correct, but we do find what some of the feedback we've received from developers that the reduced costs allows them to move forward with a business case that works for them as opposed to not. So going back to your question about exploring a fixed fee, we have not explored that at this time, but we are open to having those discussions with stakeholders if we -- if that is something that's of interest to other parties.

MS. ANCEL: And just building on -- this is Charlotte Ancel. Building on Rita's response the concept -- as I understand it, Ms. Huntington, the question is has CMP evaluated the concept of having effectively a tariffed interconnection rate similar to what Green Mountain Power in Vermont has developed. That topic has come up in the context of the interconnection working group. At the time, we did not receive incredibly favorable feedback from -- our understanding was from the developer community on that topic. That said, we're always open to having that conversation and working on a concept like that.

MS. HUNTINGTON: Thank you, Charlotte. You anticipated my oral data request which is is the company aware, and if so, could you provide, whether there are utilities in other states that have that kind of a fee in jurisdictions where utilities in other states, as we've heard, have already moved forward with approaches where they would operate operational control over the interconnecting projects to avoid the need for costly upgrades?

MS. ANCEL: Yes. To date, we -- as -- so far as we are aware that approach, that tariffed, approach has only been adopted in Vermont subject to the company's -- by Green Mountain Power subject to the company's last analysis of the topic.

MS. HUNTINGTON: Thank you.

MR. BRYANT: Faith, can you shorten that ODR a little bit? You kind of went on.

MS. HUNTINGTON: Okay, sorry. Could the company provide any tariffed or other terms governing charges for interconnecting projects related to systems that allow the utility to exercise operational control?

MS. ANCEL: This is Charlotte Ancel. Yes, and, Eric, may I just ask a clarifying question on that ODR to make sure we answer it accurately? Thank you. Ms. Huntington, I just want to make sure I understand. Your request is specific to utilities that have enacted fixed fee or tariffed approaches for interconnection contributions, not so broad -- as opposed to a broader where -- request where we would effectively provide our analysis of every utility's interconnecting tariff. You're -- the question is specific to like a fixed fee approach. Is that right?

MS. HUNTINGTON: That's fine. Yes, that -- thank you, Charlotte. That would be great.

MS. ANCEL: Okay, thank you. Yes, we will do that. Thank you.

MR. MANNING: and this is Bob Manning. And just to add, you know, I mentioned our REV, reforming the energy vision, demonstration project in New York. The -- that project proposal included platform as a service fee that we were modeling. Now that still is a demonstration project that is ongoing. So we have implemented that not as a business as usual but as a demonstration project in New York.

MR. BRYANT: Thanks, Ian. Thanks for your patience. I'll turn it back to you now.

MR. BURNES: No problem. So -- and I'm conscious I've probably taken more than my time here. So I'm going to go quick. You said that there would be additional functionality and that's part of your justification for putting the -- a certain portion of this, the 1.7, into distribution plant. If we were to move beyond curtailment of DERs as the functionality, would there be additional costs or could you do that at no cost?

MR. MANNING: Bob Manning. So there would be configuration of the system, like setting the parameters and integrating to whatever we're trying to integrate. Let's say it's loads -- bless you -- EV charging, batteries, what have you. Whatever asset we're trying to control could be building electrification. There would be some integration costs there. And then there would be configuration at the head-end system to say, you know, at this level, do this, right? This is the action we want taken. So there would be additional configuration cost.

MR. BURNES: And if you -- do you plan on testing that additional functionality, if this is approved as proposed?

MR. MANNING: So what we're proposing is to provide quarterly updates to the Commission, and then after a year of operation, we could have that discussion with the Commission. It depends on how successful the pilot is. Do we want to scale it and what functionality do we want to adopt going forward.

MR. BURNES: Okay, so you wouldn't add additional functionality without asking for Commission approval?

MR. MANNING: Correct.

MR. BURNES: All right, Eric, I think that's it for me. Thank you. Thank you to the panel for your thorough answers.

MR. BRYANT: Okay. Thanks, Ian. So next will be Competitive Energy Services and following that will be CLF and following that will be staff. Go ahead, Eben.

MR. PERKINS: Thank you, Eric. Is the panel familiar with ISO New England's Schedule 23? This is the small generator interconnection procedures.

MR. MANNING: Bob Manning. Not intimately familiar, but in general.

MR. PERKINS: Could you explain how Schedule 23 fits into your interconnection process and procedures when, say, a battery project come and ask for interconnection to operate in parallel with the grid?

MR. MANNING: So I'm not intimately familiar with the Chapter 324 of the Maine interconnection process. I don't know if we have somebody available that can discuss the state --

MR. PERKINS: I see a number of the distribution planning team in the background. Is it possible to bring up maybe Chris Morin and or somebody else?

MR. MANNING: If Chris is willing to come up.

MR. PERKINS: Thank you, Chris. So let me repeat the question. How does ISO New England Schedule 23 -- again, this is small generator interconnection procedures. How does this fit into how CMP runs its own interconnection process?

MR. MORIN: This is Chris Morin. There are separate processes that we have. The 324 process, as Bob mentioned before, we fall on the distribution side. Then those roll up to a certain point where it triggers a cluster study for us, and we do follow the 23 -- I think there's -- I forget the other, is it 22 as well, 24? I guess a couple different schedules there for different size projects. We do follow those as closely as we can. We coordinate closely with ISO New England throughout the cluster study process. The check-ins, meetings as well.

MR. PERKINS: So I'm looking at -- this is -- and I'm happy to provide this after the fact. This is Avangrid report, biweekly report, on transmission system impact studies for distributed generation interconnections dated November 4th, 2022. So these are the biweekly cluster study updates that you issue publicly. It looks like the Trap Corner substation falls within cluster ten. This is named Roxbury, Rumford, Woodstock. So my question here is if you were to bring the Trap Corner battery project forward with an interconnection application today, do you agree that this would fall within cluster ten?

MR. MORIN: I'd have to confirm that.

MR. PERKINS: Schedule 23 defines generating facility as an interconnection to customer's device for the production and/or storage for later injection of electricity identified in the interconnection request. So if one of these projects is brought forward as part of a cluster, if it's identified to be included in one of these clusters, say cluster ten, does CMP believed that the Trap Corner battery would meet the definition of a generating facility as is defined in Schedule 23?

MR. MORIN: This is Chris Morin. We would definitely look at it on a case-by-case basis. I'd have to confirm that I guess, but any generator coming onto the system, we'd have to -- a non-wires alternative, for example, as well any of those in-front-of-the-meter devices would had to be considered for applicable interconnection standards.

MR. PERKINS: So I'd like to take an ODR here. And the question is does CMP believe that the Trap Corner battery system would meet the definition of a generating facility as is defined in ISO New England, Schedule 23? That clear?

MS. TAYLOR: Yes. That's number 35.

MR. PERKINS: Thank you. That's all I had, Chris.

Thanks. So next question, does Iberdrola or Avangrid have an ownership interest in any battery storage providers? And by provider, I mean a non-regulated entity that offers battery storage design, engineering, procurement, construction, or operation services.

MS. KING: This is Rita. I do not believe so. Subject to check, but I think no.

MR. PERKINS: So the answer is no?

MS. KING: This is Rita. Yes.

MS. ANCEL: This is Charlotte Ancel. Just building on that, as Rita said, subject to check, but in the interest of accuracy since you've also asked a question about our upstream parent, we will take it -- if we could treat it as an ODR just to make sure that we are fully comprehensive in our response.

MR. BRYANT: Yeah, I think that's a good idea.

MS. TAYLOR: Can you, please repeat the question?

MR. PERKINS: Does Iberdrola or Avangrid have an ownership interest in any battery storage provider? By provider, I mean a non-regulated entity that offers battery storage design, engineering, procurement, construction, or operations services.

MS. TAYLOR: Thank you.

MR. PERKINS: So in response to CES's data request 3-001, CMP indicated that the company and Casco Bay Lines voluntarily withdrew the request for approval for CMP to own a behind-the-meter battery project at Casco Bay Lines' terminal in Portland. This was in docket number 2021-00102. So CMP in this response to our data request indicated that this decision was based on stakeholder feedback and the present lack of funding for the project from external grants. Please specify what you mean by stakeholder feedback in a data request.

MR. MADER: Jim Mader. So we held a series of meetings with -- CES was one of the stakeholders as you're aware. And the feedback was that we were really -- the stakeholders want us to pursue more of a rate design solution versus a battery solution. And as well as from that project, we also were committed to finding funding. I think we had committed to 50 -- trying to find 50 percent or more. We had many discussions with DOE trying to find specific funding for an electric ferry, and at the time we had no luck. Now, as we all know with the latest IJA (phonetic) and all the other funding that's all there, the maybe something specific to electric ferries. But at the time we didn't have any -- couldn't find anything that fit the bill.

MR. PERKINS: So by stakeholder feedback here in this response to the data request, you don't include the comments that were jointly filed by CES, Efficiency Maine Trust, the Industrial Energy Consumers Group, or the Maine Renewable Energy Association on June 8th, 2021, in the case?

MR. MADER: I' have to look at the comments to be honest.

MR. PERKINS: So let's just talk through the timeline of how we've gotten from that case to here. So May 2021, the docket I just referenced, 2021-00102 got initiated. CMP filed the request for approval to own the battery solution at Casco Bay Lines. In November 2022, CMP withdrew the petition. August 2022 CMP submitted its initial filing in this proceeding. So between the time when the parties I just mentioned jointly filed comments in the Casco Bay Lines docket in June 2021, it's over a year to when CMP initially filed in this case. I'm confused here about the prior references to collaboration on this project with the intent to work with stakeholders around these battery proposals. My question is over that period between June 2021 and August 2022, did CMP approach Efficiency Maine Trust or the OPA to discuss whether each party had any concerns about the utility owning battery solutions?

MR. MADER: Jim Mader. Yeah, so as we said in our filing, we want to work with stakeholders should the Commission decide that these projects, you know, could move forward. So I believe the answer is no, we have not spoken about that specific topic. We have -- we did incorporate, though, some of the feedback from those discussions on Casco Bay about behind-the-meter storage and decided that behind-the-meter storage -- we'd rather focus on front-of-the-meter storage which, you know, may incorporate more into the utility system itself.

MR. PERKINS: So let me just confirm that. Prior to developing and filing the proposal to own the Trap Corner battery and the Woolwich battery, CMP had no discussions with any of the intervenors in that Casco Bay Lines case around the concern of utility battery ownership?

MS. ANCEL: This is Charlotte Ancel. If I could just respond, Jim. So I can speak to my own experience speaking on behalf of CMP. We have had dialogues certainly with Efficiency Maine Trust, I have had dialogues with Efficiency Maine Trust, on that topic. I'd like to speak to just amplify what Jim just said on behalf of CMP. We did initially get involved in the Casco Bay battery storage project because our understanding of it was that there was an interest in helping to make the project go forward. We did subsequently get feedback from the stakeholders that Jim and Rita have described that aligned with our overall policy view. And I can -- I'm, pleased to speak on behalf of CMP and say we are not interested in owning behind-the-meter storage. We don't think that that's a necessary place for us to serve our customers. The Casco Bay experience did help us to clarify, from a policy perspective, that view. We do have an interest in some circumstances where there is a direct grid benefit to own in-front-of-the-meter storage and that grid. The battery storage would be -- in-front-of-the-meter battery storage would be effectively the same thing as other grid assets that we might use and would have direct grid benefits to serve our customers. In some circumstances, we do have an interest in exploring that, and that's reflective in the Trap Corner battery project that you described.

MR. PERKINS: In response to Examiners 10-036, CMP indicated that there was no review of non-BESS -- BESS being the acronym for battery energy storage system. So there's no review of non-BESS alternatives to the overload need at the Trap Corner substation. Does this include examining the cost of replacing the 3.45 MVA transformer at Trap Corner substation to increase its nameplate capacity?

MR. MADER: Jim Mader again. Yeah, no, we did not look at that cost yet. We -- as we indicated in the filing that these are pilot projects, and typically running a cost comparison for pilots doesn't tend to lend this up to very positive BCA.

MR. PERKINS: So forget the pilot for a second, though, just the cost of upgrading the transformer to address the overload need. Not talking about batteries here. CMP didn't look at the cost of replacing that transformer, that hasn't been quantified to date?

MR. MADER: To date, no, it has not.

MR. PERKINS: And the upgraded capacity, the planned nameplate capacity, of that upgraded transformer that hasn't been quantified to date?

MR. MADER: I think it's subject to checks because I'm not a hundred percent sure, but I don't believe it has.

MR. PERKINS: Same question for the Woolwich substation. Has the cost of upgrading that substation transformer been determined to date?

MR. MADER: Same response. No.

MR. PERKINS: All right.

MS. KING: This is Rita. Can I address that as well? So while we have not costed out that traditional solution, as Charlotte has mentioned, CMP does feel that going forward, if we are going to be able to understand how energy storage is going to impact and help address the transformation of the system, we need to be able to have some direct hands-on experience with the asset itself. And not in every case, but in these two particular cases, we're looking at assets within the substation that serves a specific, pretty, you know, complementary type of use cases. And so the idea here was for us to be within the bounds of these pilots, learn some lessons for our field folks, for our planning folks, for our operations folks, and to be able to understand this emerging technology which, at some point in the future if we're going to meet Maine's renewable and clean energy goals, we're going to need to have a lot of energy storage on the system. And if we as CMP don't understand how that asset works in tandem with the rest of our system, it's going to be really hard for us to be able to continue to supply safe and reliable service to our customers.

And so you know, this is an opportunity for us to do that. We looked for the type of integrated system asset to propose a storage pilot so that we can start those lessons learned. You know, I don't know how long it's going to take for storage to take off on, you know, distribution systems, but if we wait until we have a lot more storage on the system, we've lost an opportunity to get ahead of that and to continue to grow our learnings in this space. And so I just want to make sure it's clear what we're trying to accomplish with these pilots as opposed to maybe just the traditional solution which, of course, we're also willing to -- you know, to look at.

And the other thing I'll mention about these pilot programs is we're looking to explore if these are the sort of threshold opportunities that the Commission is willing for CMP to engage in, and we do see a storage as being very integrated into the system going forward. You know, storage could be a transformer for us, can be the type of asset that really has day-to-day implications to our system. And so we're trying to get some experience now before it becomes more impactful and more costly for us to do that.

MR. PERKINS: In the course of developing either the Woolwich battery proposal or the Trap Corner battery proposal, did CMP engage any battery storage developers to ask the question, if there was a third-party-owned battery providing the same applications, why couldn't those technically provide the same services if the battery owner offered to grant control, direct control, through the ADMS system you're developing under certain conditions? Did you have that conversation with any battery storage developers?

MS. KING: This is Rita. No, we did not.

MR. PERKINS: All right. When was the last time CMP communicated with the developers of the one-megawatt and the two-and-a-half-megawatt solar projects being developed at Trap Corner substation that were referenced in your testimony?

MR. MADER: Could you -- which question was that in the --

MR. PERKINS: So there's a -- the test --

MR. MADER: No, I understand, but was it -- which question did you submit that we could -- I could refer to to check?

MR. PERKINS: Not referencing one of our data requests here. Your testimony references one-megawatt solar project under development at Trap Corner and a two-and-a-half-megawatt solar project. When was the last time CMP communicated with the owners of either -- or I'd say both of those projects to confirm that those projects are still proceeding?

MR. MADER: So I would have to check with our DG folks. I'm not sure. I'm sure we've been communicating with them back and forth on interconnection studies and what not, but I don't know the exact date of the last communication.

MR. PERKINS: But this panel hasn't specifically had a communication with them to ask, in light of rising costs, cluster study concerns, other issues, that they're still planning to proceed? So outside of just the interconnection steps, has that broader communication happened?

MR. DES ROSIERS: Objection to form. If the question is has the panels (sic) communicated, I think that's a fair question for this panel.

MR. PERKINS: I thought that's what he asked -- that's what I asked.

MR. DES ROSIERS: I believe, if we review the record, there were multiple questions in the last. So if you want to clean it up and just ask the panel have they communicated, that would -- they would be able to answer that.

MR. PERKINS: As this panel communicated -- so this panel, have you communicated with the owner -- the project developer of the one-megawatt project at Trap Corner and the two-and-a-half-megawatt project at Trap Corner to confirm that these projects still plan to proceed to construction?

MR. MADER: Jim Mader. No, we have not.

MR. PERKINS: Does CMP plan to install any telemetry with the existing solar generation installed at the Woolwich substation?

MR. MADER: Jim Mader again. We would certainly consider that as part of the project, but there's no definitive plans right now.

MR. PERKINS: Is there any proposed front-of-the-meter solar currently in the interconnection queue at the Woolwich substation?

MR. MADER: I -- so I'd have -- we'd have to check.

MR. PERKINS: Take that as an ODR, please.

MS. TAYLOR: So the question is there any -- currently any front-of-the-meter telemetry land at the Woolwich substation?

MR. PERKINS: I'll restate it. So is there currently any proposed front-of-the-meter solar that's seeking to interconnect to the Woolwich substation that's in the interconnection queue.

MS. TAYLOR: Thank you.

MR. PERKINS: Going to Trap Corner here and thinking about the reliability concern that you're trying to address, and this was detailed in the testimony. Let's say that downstream of the Trap Corner substation, there is a tree-related conductor outage or a wind-related conducted -- conductor outage on one of the feeders. Could the battery still work in islanding mode if those -- if an outage like that happened? Would it -- could it discharge into those feeders if there is a downstream outage?

MR. MADER: Jim Mader again. So could it or would it I guess is --

MR. PERKINS: Can it?

MR. MADER: Can it? Can it can discharge down into -- so if there's a an outage on the circuit itself, a tree took a conductor out of single phase, three phase, two phase, we would put the proper protections in place to ensure that it wouldn't -- you know, that conductor would not stay live with the inverter-based battery system. So that's all -- that would -- I just want to clarify too that would all be part of detail design which we have not done yet with this project, but we would consider all those scenarios as part of that.

MR. PERKINS: So from a standpoint of keeping lineworkers safe, your operations procedures, the battery cannot be allowed to discharge if there's a downstream outage? While that downstream outage is in effect, you have to keep that battery from discharging?

MR. MADER: Yeah, we would follow all our safety and -- safety protocols to make sure that, you know, nothing was energized that shouldn't be.

MR. PERKINS: So from a reliability standpoint, the battery can only be used if there is an issue, an outage, an unplanned outage, with the substation transformer or the subtransmission feed serving Trap Corner substation. Is that correct?

MR. MADER: Jim Mader again. So you're asking if there's an outage with the transmission line or a problem with the battery -- I'm sorry, a problem with the transformer, the battery could only solve those issues? Is that -- I think --

MR. PERKINS: There's three types of outages here. There's the subtransmission feed into the substation, there's the substation transformer, and then there is an outage downstream of this substation on one of those feeders. Is it correct that the battery can only be used for the first two outages, that it can't be used for the third category of downstream outage?

MR. MADER: Oh. Jim Mader again. Yes, actually that was in the testimony of the purpose of what the battery was resolving.

MR. PERKINS: Great. So --

MR. DESROSIERS: This is Adam Desrosiers. Can I add to that?

MR. PERKINS: , please.

MR. DESROSIERS: Over here. I don't -- I guess in the situation you just described, I don't see a situation where the battery would be necessary if the fault was downstream on the distribution circuit because the substation transformer would still be in service at that point and the downstream protective device on the distribution circuit would have cleared for that fault. So whether it's the battery or the substation transformer, the customers ahead of that fault or the head of the next protective device would still be -- still have power.

MR. PERKINS: That's helpful, Adam. So just a follow-up question on that. So this battery won't reduce -- or if you're looking back in time, this can't reduce any outage hours that occurred because of downstream outages?

MR. DESROSIERS: Not on the distribution circuits, but if this battery was designed and programmed such that it could essentially island that transformer in the case of a subtransmission fault or a substation fault, to me there is benefit there and being able to carry the distribution circuits.

MR. PERKINS: Thank you, that's very helpful. I'm going to move now -- okay? I'm going to move to the grid model enhancement project. I'm assuming I can combine the 30 minutes all together. So page 25 of this panel's testimony stated that the GMEP, the acronym we're using here for the grid model enhancement project, it has a capital cost of 12.58 million. In response to CES's data request 3-019, CMP indicated that the specific resources and cost needed to complete the field connectivity survey have not been determined yet. So I'm a bit confused. Does that 12 and a half million and change -- does that include the field connectivity survey to clean up your data or does it not?

MR. ALONSO: This is Miguel Alonso, the project manager of the GMEP project. Yes, that estimate that we filed includes the field survey.

MR. PERKINS: So how much of that 12 and a half million is the field survey? And you can be approximate.

MR. ALONSO: So the project is right now in the planning stage. So we don't have a breakdown specific of how much is going to be the field survey and how much are going to be everything else. It's subject to the procurement process that it's planned and ongoing when we will be able to break down those categories in a much further level of granularity.

MR. PERKINS: So in response to CES's data request 3-020, the company indicated it first identified the need for a comprehensive field connectivity survey during a similar effort that was proposed in Avangrid's New York subsidiary rate cases in 2019. Did CMP not conduct CYME studies for interconnection applications prior to 2019?

MR. ALONSO: This is Miguel Alonso. As far as I know, CMP has been conducting CYME studies for a long -- a longer period than that.

MR. PERKINS: So for these studies that were conducted before 2019, was the distribution data for those feeders that were uploaded into the CYME model -- were those -- do they have clean data or --my understanding is this is a systemwide issue.

MR. ALONSO: This is Miguel Alonso. It depends on the specific issue that we're talking about, but (indiscernible) may include if one of the items that is in scope of the grid model enhancement project that we're going to be filling in is, for instance, the customer to transformer allocation and the phasing information, knowing which phase is carried by each transformer. Those are data points that are quite relevant for the CYME modeling that currently exist, but as a result of the GMEP project, it's going to be more accurate or it's going to be filling existing gaps that currently exist.

MR. PERKINS: Let me ask this a different way. So the data request says -- the response says you identified this data quality issue in 2019, but you've been conducting distribution interconnection studies way before 2019. How do you -- help me square those two items? It seems like a distribution planner would have seen these issues prior to 2019 in the data.

MR. ALONSO: That is correct.

MR. PERKINS: Was there any discussion at CMP when Governor Mills was elected in 2018 about the need to clean up the distribution data in your system with Governor Mills', or at the time Candidate Mills', proposed solar initiatives and the impact those initiatives would have on interconnection demands?

MS. ANCEL: Could we -- this is Charlotte Ancel. Could we just huddle for a second to determine the right witness to answer that question?

MR. PERKINS: , please.

MS. ANCEL: Thank you.

MS. MCDONOUGH: And while we do so, this is counsel for CMP. Chris Morin has the answer to a previous ODR if you'd like that.

MR. PERKINS: Sure.

MR. MORIN: This is Chris Morin. So, Eben, about your question previously regarding ISO's Chapter -- Schedule 23 and Trap Corner. After reviewing quickly planning procedure 5-1, it would not require Schedule 23 review because it will be operating not in parallel with the grid and it'll be a microgrid. So disconnected from the actual system is when it'll operate. But it's greater than one megawatt.

MR. PERKINS: I think the ODR was a separate question than that, but that's a helpful response.

MR. MORIN: Was it?

MR. PERKINS: Yeah.

MR. BRYANT: I think the ODR referenced the Commission's rule, not ISO's.

MS. TAYLOR: No, it referenced ISO's. What I have -- yeah, what I have is whether or not it meets the definition under ISO Schedule 23.

MR. MORIN: All right, it --

MR. PERKINS: Thanks for looking.

MR. MORIN: It would not.

MR. PERKINS: Okay.

MR. BRYANT: So does that mean you don't need your ODR?

MR. PERKINS: Is your -- did you just say no?

MR. MORIN: It would not require any analysis under that.

MR. PERKINS: Still need the ODR.

MR. BRYANT: Okay.

MR. PERKINS: Yeah.

MR. BURNES: And I have a follow-up question for that, if there's -- maybe why you guys huddle --

MR. BRYANT: Fire away.

MR. BURNES: -- I can ask Chris. Or actually, I don't know. The fact that you're studying this only in islanding mode, does that limit the number of scenarios that you can test that we discussed during my testimony? I believe there were multiple scenarios, many of which would require it to be operating outside of islanding mode. Just wondering whether the panel actually considered that in the pilot design.

MR. MADER: This is Jim Mader. Could you repeat the question? Sorry.

MR. BURNES: When you looked at the scenarios that you would be testing, including peak shaving, regulation, energy markets, and reducing the peak loading of the transformer, did you consider whether or not the battery would operate outside of simply islanding mode? So it would be actually operating in parallel with the grid?

MR. MADER: Yeah, I assume this is for the Trap Corner station. So yes, the battery would be operating in parallel. And then if there was an issue --

MR. BURNES: So, Chris, do you want to change your answer?

MR. MADER: If there was an issue with the line on the transformer, it would go into microgrid mode.

MR. BURNES: Sounds like it's operating as microgrid and in parallel.

MR. MADER: If -- Jim Mader. If that was a question, then yes, it would be operating in both.

MS. KING: This is Rita.

MR. BURNES: Chris, does that change your answer?

MR. MORIN: This is Chris Morin. So basically ISO New England's planning procedure 5-1, anything greater than one megawatt would require some level of analysis. That's not running -- that is running in parallel with the grid. So if it is running in parallel, it could require some analysis from ISO New England. And for Woolwich, for example, it's less than one megawatt. So nothing is required for Woolwich, even though it will be peak shaving running in parallel. Trap Corner's doing both, and it will require some coordination and most likely a study from ISO New England.

MR. BURNES: Okay. Thank you.

MS. ANCEL: This is Charlotte Ancel on behalf of CMP. To respond to Eben's earlier question that related to 2019 -- the company's approach in 2019 after the election of Governor Mills, we would take that -- that is a question that is better directed to the planning group and people who were specifically in the company at that time. So we'd like to take that as an ODR, please.

MR. PERKINS: Okay.

MR. BRYANT: We'll need that text for that ODR, Eben.

MR. PERKINS: Give me just one second. I need to just frame this clearly. So for the ODR, the question is for interconnection studies that were conducted prior to 2019, did any of those studies, while the CYME model was being developed, encounter distribution data quality issues?

MR. BRYANT: And CYME is an acronym, C Y M E?

MR. PERKINS: C Y M E, CYME. Good?

MR. BRYANT: Okay. Thanks.

MR. PERKINS: Who is ultimately responsible for the quality of your distribution system data? And this could be at CMP or Avangrid. Where does the buck stop?

MR. DES ROSIERS: -- directed to this panel or to the company as a whole? Because I don't believe --

MR. PERKINS: To this panel, yeah.

MR. MADER: Jim Mader. Sorry, I didn't know you were directing it to us. I think we would have to talk with folks who do that specific task in the company.

MR. PERKINS: Can you specify what you mean by those folks?

MS. KING: So this is Rita. The -- with respect to the quality of the data of our distribution system, we actually have a process that has joint ownership across many of the business areas. And what I wanted to do was, if I could, go back to the question you asked about prior to 2019 when we identified the need for the comprehensive survey, how our planners were executing some of the studies that were required.

MR. PERKINS: I'd prefer to keep the focus on this question of responsibility, and I'll try to clarify a little bit. My understanding, Adam Desrosiers oversees all of the field operations team. Is that fair to say?

MS. KING: This is Rita. That's correct.

MR. PERKINS: So for these field workers, if they have to change out a component on the system, recording that data and making sure it gets back into the system correctly, is the distribution system data quality -- is this Adam's responsibility ultimately? If Joe is asking, you know, who's responsible for this, is this Adam? Is it the head of Avangrid information technology? Is it just a management person in a separate department?

MS. KING: So this is Rita. As I mentioned, there's joint ownership of the data. When you look at the process of the data out in the field, yes, our field employees are responsible for the data. Once that data comes into our system, we have a number of different business owners that will need to touch and use that data across that process. And so there is a collective ownership of the data across the end-to-end process.

MR. PERKINS: So is that collective ownership formally documented in a data governance and quality plan at the CMP or the Avangrid level?

MS. KING: This is Rita. My understanding, that's something we are developing and working on.

MR. PERKINS: So it doesn't currently exist?

MS. KING: This is Rita. I do not believe so.

MR. PURINGTON: So this is Joe. So this -- depending on the type of data that we're talking about there, but there's processes in place from a design perspective when the field planner goes out in the field to design the job, to look at the data that's there. Also when we have -- when we're building and constructing, the data that -- you know, the field planner designs the job. The line crews go out. They may or may not necessarily build per the design. They'll do an as-built change. That as-built change will get entered into the SAP system which will feed the GIS system. That's the process. We can get a process flow chart for you on the data quality management, but also I think when we get back to the data quality question, is, I think as Alonso mentioned, the accuracy in that process of getting, you know, transformer to a phase to customer is -- we don't have that. We're not confident in that data. And as we go through -- and there's a variety of reasons. As we go through storms, we have a bunch of contractors come in. If we replace 500 transformers, you know, the accuracy of the records coming back in is not solid. So as we go through this process, we'll go through and get the accurate data, build our model, allow the control center to use that to help manage the system operations, and improve the process of how we manage that data. That's integral. The speed of which those changes occur need to be, as I mentioned earlier, upfront, especially when we have planned improvements to the system so that the operating model is correct for our operators. So it's a variety of -- that's why -- it's a variety of avenues that the data gets, you know, validated.

MR. PERKINS: That's really helpful. So let me just ask a follow-up question to that. If the Commission approves, what is this, 12 and a half million, plus or minus, to clean up this data, is there a formal plan in place that's already been adopted and approved at the Avangrid level to ensure that this data quality issue doesn't recur in the future?

MR. ALONSO: This is Miguel Alonso. Yes, part of this project, of the GMEP project, involves not just capturing information in the field and putting it back into our systems, but also to identify and execute processes that are streamlined that allow traceability and that ensure that we follow the lifecycle of the asset and its data from its origination till its end of life, and that along the way we've defined the processes that involve several business areas to ensure that the data stays accurate and reliable in the long term.

MR. PERKINS: When a distribution planner receives an interconnection study request and they have to set up a CYME model to run that interconnection study, if you have a project proposed to interconnect on a feeder where you have this distribution data quality issue, how many hours does it take on average for a distribution planner to clean up that data, be able to run the CYME model?

MR. ALONSO: This is Miguel Alonso.

MR. DES ROSIERS: (Indiscernible) the right person to ask.

MR. ALONSO: That's what I was going to say. I'm not a I'm not a field planner. I'm a distribution planner.

MR. PERKINS: No, no.

MR. ALONSO: So they can answer that directly since (indiscernible) and they will.

MS. CULLEN: This is Kimberly Cullen. It honestly varies depending on the circuit itself, but it can take upwards of 8 to 16 hours to clean up the model.

MR. PERKINS: Is it okay to -- let me tell you -- tell me if you disagree with this. On average, cleaning up data for an individual feeder takes 8 to 16 hours. So let's pick 12 hours as the midpoint. Is that fair as an indicative average

MS. CULLEN: Let's say 16 on average.

MR. PERKINS: Okay. And in -- since L.D. 1711 was passed, has this manual data cleansing process had to occur for every feeder in CMP's service territory?

MS. CULLEN: That is correct.

MR. PERKINS: I'm going to do a quick time check. Okay, I go for five, ten more minutes?

MR. BRYANT: Five would be good.

MR. PERKINS: Five would be good. I will try to keep it short. The advanced distribution management system, this is, for an acronym, ADMS, I'm a little bit confused of where you are in the process of implementing the ADMS system. And my understanding when we say ADMS, I believe that's the same thing as saying seam and spectrum (phonetic). Tell me if that's incorrect. Where in the process are you in rolling out this system?

MR. SADLER: This is Matt Sadler. So right now we're in the process of implementing seam and spectrum. First, the energy management system, so the SCADA piece of it, and then the outage management system. And the ADMS is a build-on to the outage management system, and that's still in the planning stages to my knowledge right now.

MR. PERKINS: So there isn't an estimate right now of timeline of when the ADMS system would be in place and operational. Is that correct?

MR. SADLER: That's correct. I do not have one right now.

MR. PERKINS: Is there a total cost estimate of what the implementation of ADMS will cost ratepayers?

MR. SADLER: I don't have an estimate of that right now either.

MR. PERKINS: This distribution system data quality issue, how does it impede the functionality of the ADMS system day-to-day for, you know, an operator under your supervision, Matt?

MR. SADLER: Can you repeat the question, please?

MR. PERKINS: So if you think about what functionality the ADMS provides to an operator, how does this distribution data quality issue -- if you don't have good distribution system data, including GIS data, how does that impact the functionality of the system for an operator?

MR. SADLER: So part of the GMEP project, like you've heard about earlier, is to clean up that data, and we are going to need the data points as part of that project for the ADMS because you have to have accurate data in the system to be able perform load flows on the distribution. And that's -- so it's critical. So it's going to follow the GMEP project.

MR. PERKINS: So is it fair to say that until the GMEP project is complete, none of the ADMS functionality can be utilized by an operator in the control center?

MR. SADLER: I think that's a fair assumption.

MR. PURINGTON: Yeah, this is Joe. So I might add, Eben, that I'm not sure that none of the functionality would be able to be used. It's going to be a question of different aspects of the functionality and whether or not you -- obviously the data has to be accurate for you to feel comfortable in letting it operate.

MR. PERKINS: Yeah.

MR. PURINGTON: And that -- I think that's your point. And for us, again, that's another reason for doing this GMEP project, to ensure that we get the right data accuracy and we can use the ADMS as a -- feel confident in using it when it's deployed.

MR. PERKINS: Okay. A few more questions here. I know my time is running short. How was the Winslow Lakewood cluster selected for the active network management pilot?

MR. MANNING: Bob Manning. So we've met with -- CMP has met with the developers in that area, and there is an interconnection agreement with each developer. And the plan is to actually do manual curtailment during certain contingencies. So I believe they're N-1-1 contingency. So if we have a planned outage, taking a line out, a transformer out, or what have you, and then we have that -- before that second contingency occurs, we're going to disconnect certain DER facilities. So the thought was you implement the active network management pilot there, that would be an automated process. And it would only be curtailed when needed, right? A day like today that's mild, there's no -- not much heating or cooling load, maybe we do not have to curtail those generators, right? So the generators could stay on during an N-1 contingency.

MR. PERKINS: So was that meeting -- were you -- you know, tell me if you disagree with this. It sounds like there was a meeting with the developers in that cluster where you sort of floated the idea of an A&M pilot. Was that same type of meeting offered to developers in other clusters?

MR. MANNING: So I was not a participant in those meetings. We do have regular meetings with the DER stakeholders, and I believe one of the data requests we provided a couple presentations that we've presented to the DER stakeholders and A&M was mentioned to that. So I'm not sure if it was offered to other cluster areas there. There was another cluster area, and I don't have the name, that we said we may look at potentially implementing A&M. Why the Lakewood Winslow was selected, again we have a plan today where they can interconnect, although it's a manual curtailment process that's really not scalable if more and more clusters or more and more DER assets come online that require curtailment. And then there was another data request about what if the pilot fails. So if the pilot fails, we have a plan in place today, right? So we're not at impacting 66 megawatts of distributed generation, right, that has invested to connect to the system.

MR. MORIN: This is Chris Morin. I could probably add onto that a little bit, Eben. Just regarding your original question about did we consider this for other clusters as well. So we do have a third-party contractor that looks at a challenge session to consider kind of outside-the-box alternatives for these cluster studies, and they come up with these scenarios for us as well, kind of on the developer's behalf, if you will. It was considered for every cluster study. Unfortunately right now during the ISO's requirements, it's only under very certain conditions we can actually pursue that. So for that one cluster study, in the Winslow, it was driven from local contingencies on local system issues. If it was a BESS contingency driving the issue, even a local system ISO won't allow it because the tariffs don't allow us to do that. So that's why Winslow is really the first one. We tried the Stanford area, but it was a BESS contingency driving it. So we got shot down by ISO New England. We do consider it for every cluster study.

MR. PERKINS: Okay. Last question. I didn't see any proposed changes to Chapter 324 in terms of basically allocating this 2.2 million for the A&M pilot to ratepayers. Is that something that's forthcoming? There were no proposed revisions to Chapter 324 included in your testimony. Is that fair to say?

MS. ANCEL: Yeah, I think our testimony speaks for itself, and yes, there are no proposed amendments to Chapter 324 in our testimony.

MR. PERKINS: That's all I had.

MR. MANNING: And just to clarify it, the A&M pilot cost was 1.7 million. You quoted 2.2 million.

MR. PERKINS: There was a 2025 cost of 450,000. So I guess the -- adding those two together, what's the difference between those two?

MR. MANNING: Okay, and that's contingent upon the pilot being successful and moving forward.

MR. PERKINS: Okay. Those are all the questions I had. Thank you.

MR. BRYANT: Thanks, Eben. I have a follow up. Has the company looked at A&M projects for interconnection at the 34.5 kV level?

MR. MANNING: We have not. I mean, active network management could be applied at -- oh, Bob Manning. It could be applied at the distribution level or potentially the transmission. I mean, we'd have to review the ISO New England planning criteria to make sure that that is viable.

MR. BRYANT: Okay. Thanks. Okay. So thanks, Eben. Next is Phelps Turner, Conservation Law Foundation. Go ahead, Phelps.

MR. TURNER: Thanks, Eric. I want to turn the panel's attention to page 16 of the testimony. This is where you describe the Trap Corner project. On line 18 you mention that the project will include installing associated microgrid equipment. What does the CMP button mean by associated microgrid equipment?

MR. MADER: Jim Mader. So that would include a controller, potential switching devices in the field. It depends on what the final design would be for the project, but those type of devices would be included as part of the microgrid equipment as we mentioned.

MR. TURNER: Okay. And would CMP update the Commission in terms of what equipment ultimately it was going in at the site location?

MR. MADER: Jim Mader again. Absolutely.

MR. TURNER: In developing this case, and in this testimony in particular, how did CMP identify the Trap Corner and Woolwich projects as the energy storage -- the pilot energy storage project that it was going to advance here?

MR. MADER: Jim Mader again. I have to look. We actually answered that question, I think, earlier in one of the Examiners. But if you give me a second, I'll look it up for you.

MR. TURNER: Thanks.

MR. MADER: Apologize for that. Jim Mader again. Yeah, Examiners 10-35 where we walk through the process for choosing the type those two particular stations.

MR. TURNER: Okay. Thank you.

MR. MADER: I can give you at a high level if you'd like. We looked at the stations that have loading of 90 percent, thereabouts. We looked at the transformers at the stations to make sure they were in good asset condition. We didn't want to install energy storage at a station that we have to replace the transformer in a couple of years anyways. And we also looked at the reliability needs of those stations. So at a high level, that was the approach. I believe in the --

MR. TURNER: Okay, thank you -- oh, I'm sorry, go ahead. I see the reference to the attachment as well. Thank you.

MR. MADER: Okay.

MR. TURNER: Is there anything else you want to add?

MR. MADER: No, I was just going to say we -- you know, we looked at about -- in that attachment there's, I think, ten stations in there that we looked at.

MR. TURNER: Okay. That's helpful. Turning to page 17 on -- starting on line six, the panel states, "This pilot will demonstrate how the use of energy storage can be leveraged as more DERs are connected to the system to develop green microgrids to help improve resiliency. How -- and then it continues on, but my question is about resiliency. How, during this pilot, does CMP plan to measure impacts of the project on resiliency?

MR. MADER: Jim Mader again. You know, off the top of my head, it would be, you know, how long -- you know, for -- well, did the microgrid, you know, do its job, did it maintain reliability and resiliency for the customers during the appropriate amount of time as planned. And I don't know if we would develop specific SAIDI/SAIFI type metrics for it, but that's something we can consider. And we certainly look for stakeholder input as to what we should be measuring as part of that project.

MR. TURNER: And I know you said it was off the top of your head. So today you haven't developed a set of metrics for measuring performance at the at the Trap Corner project?

MR. MADER: Jim Mader again. At this time, now, we haven't come up with specific measures.

MR. TURNER: Turning to the next page, page 18, starting at line 12, the panel references -- or discusses Maine's declaration of the policy on smart grid infrastructure, and there's the citation in the footnote to Title 35-A, Section 3143. This reference is in a discussion about ownership, but my question is somewhat different. It's more generally in CMP's view, how did the proposals outlined in this panel's testimony advance Maine's smart grid policy?

MS. KING: This is Rita. So I think I addressed it a little bit in a previous response. I think when we think about the types of impact that this emerging technology can have on our system going forward, it's important for us to be able to understand how storage assets are going to both impact our system as well as be able to be used in order to help deliver benefits to the grid and to our customers. And so I think just at a high level, that's my response, being able to understand the benefits and functionality of the -- of energy storage is going to be important for us in order to advance the transformation of the grid as well as clean energy goals that we have here in the state.

MR. TURNER: Thanks. And I guess a follow up would be do you think that the declaration of policy on smart grids should be one of the criterion by which the Commission assesses these projects -- or these proposals?

MS. KING: This is Rita. I think it's a consideration.

MR. TURNER: Turning ahead to page 30, starting on line 13, the testimony states, "The integration of large numbers of DERs and electrification of loads is fundamentally changing the way we need to plan and operate the distribution system." To what extent will the proposals outlined in this testimony allows CMP to meet anticipated needs of -- associated with two-way power flows and associated with electrification?

MS. KING: So this is Rita. I think the proposals in this filing that we've submitted are a starting point. They allow us to think about electrification with our make ready which, in many of the other states that we do business in -- across the country, actually the types of make-ready programs that we've proposed are pretty common because they really address one of the larger obstacles that we've heard from our customers around EV adoption rate which is range anxiety. So the make-ready programs really seek to further charging infrastructure to help and directly address that type of obstacle for electrification of transportation.

With respect to the two-way power flow, I think when we think about GMEP and having the data that we need to be able to use some of the other functionality within the systems that we have within the company, that, again, is a starting point for us to start to better understand how two-way power flows are going to impact and what we need to do to continue to have more DER deployed on our system. So, again, I think these specific initiatives are a starting point.

MR. TURNER: Okay. Last question. I CMP's view, if there were utility performance metrics associated with grid modernization and technologies and metrics associated with furtherance of energy and environmental policies by either voluntary metrics developed by a utility or less voluntary metrics developed by the Commission, would that help the Commission and the parties assess the proposals in -- proposals identified in this testimony?

MS. KING: So this is Rita. I believe that there are metrics that, from a -- for some of the initiatives would be appropriate. We have a number of metrics that we track in some of the other jurisdictions where we have similar programs, and I think those are probably translatable for the most part here in Maine. And I think that metrics with respect to tracking for performance of their programs, of course, that's very appropriate. I'm not sure about performance metrics. I think about, just as an example, if you think about transportation electrification, there are probably some metrics that are appropriate to track from a program performance perspective, but I would caution on metrics such as customer adoption of EVs because that's not directly within CMP's control. That requires our customers, obviously, to take action. So I think those metrics need to be carefully considered. And if we're thinking about performance metrics versus tracking metrics, we certainly want to have a conversation around what that definition looks like, and certainly happy to talk to stakeholders about metrics in general.

MR. TURNER: Okay, thanks to the panel. No further questions at this time.

MR. BRYANT: Thank you, Phelps. Now the staff, I think, has some questions for the panel. I know Greta does. I know Commissioner Scully does, and I think you do.

MR. DAVIDSON: Yeah.

MR. BRYANT: Okay. I don't care who starts.

MS. HEIMGARTNER: Why don't I start? (Indiscernible) my (indiscernible) down. This is regarding the Woolwich battery and the Trap battery systems. Has CMP identified systems to communicate with those batteries, such as, you know, at their ECC and how that process would be done?

MR. MADER: Jim Mader. It's a good question. So are you kind of thinking, like, real-time data, performance of the battery, is the battery on or off, state of charge, etc., like that? So we would incorporate that into our existing processes and systems, and to the extent that we would need to make modifications, I would assume we would make modifications. I will say I'm not an expert in what we have for the current SCADA system. Yeah -- so, yeah, that's --

MS. HEIMGARTNER: So given the fact that the battery -- the batteries have not been purchased or even designed yet, you haven't thought about that, an interconnection communication process? Because there will be software issues.

MR. MADER: No, good question, and that would actually be all scoped out in the RFP and the detailed design aspect of the project. So we would make sure that, you know, whatever communications protocols we would use, the system that we would use to communicate back and forth, would all be included as part of that effort.

MS. HEIMGARTNER: Exhibit CIP-2, page five of five, you have money being spent in -- significant amount of money being spent in 2023 and 2024. Is -- this has not even been scoped and designed, let alone purchased. How could you spend all that money in 2020?

MR. MADER: Jim Mader again. Yeah, so what we did was, based on our experience with spending of projects, we -- as I think we mentioned in one of the earlier days, we did the pilots up in New York. We estimated a spend about 70 percent upfront and then 30 percent on the back side. So -- and we figured about 18 months to develop the projects. So we used the estimated cost and then just kind of split the money up based on that kind of allocation. And then once we finalize the scope and we go out for bid and get more firm pricing, we'll then refine that estimate and that estimate spread accordingly.

MS. HEIMGARTNER: Okay. Thank you.

MR. SCULLY: I'm going to beat on the battery horse as well with a couple of questions if I could. With respect to Trap Corner, my understanding is that this could address potentially two different issues. One relates to backup in the event of an N-1 kind of contingency, and the other relates to the overload on the transformer. I'm assuming that the likely solutions to the backup question, in the absence of this project, would be some kind of a cross connection, or whatever the right term is, to another substation. Is that fair?

MR. MADER: Jim Mader again. Yes, it would be circuit ties which there currently are none.

MR. SCULLY: And the company is proposing circuit ties -- the implementation of circuit ties as a part of its overall capital improvement plan. Is that right?

MR. MADER: Jim Mader again. Good question. I'm not sure if that particular station --

MR. SCULLY: I'm not looking at you. I'm looking at -- that's really a separate question. I really meant in general.

MR. PURINGTON: Yeah. Yes. Joe again.

MR. SCULLY: Okay. And -- but I take it that the company doesn't currently plan, within the three years of this proposed rate plan, to institute a circuit tie at this particular location. Is that correct?

MR. MORIN: This is Chris Morin. I can take that, answer that question. So Trap Corner was selected for the microgrid mainly because of its remote location. There's not many sources nearby at all. So getting a circuit tie would be very expensive. So we thought it'd be a great location for a microgrid pilot.

MR. SCULLY: Okay. And you don't have, in the current case, a proposal to replace or upgrade the transformer at Trap Corner or the transformer at Woolwich. Is that right? That's not in the case currently?

MR. DESROSIERS: This is Adam Desrosiers. No, there's no plans. At this point, those transformers are not overloaded. They're at 90 percent of nameplate.

MR. SCULLY: Okay. And in the event that the pilots don't happen, would it be your intention to rejigger your capital plan and replace those transformers within the three-year period of this rate plan?

MR. DESROSIERS: We would only do that if they became overloaded.

MR. SCULLY: And they're not currently?

MR. DESROSIERS: That's correct.

MR. SCULLY: And do you project them to be overloaded in the three-year period? To the extent you have projected that at all?

MR. DESROSIERS: No, we do not.

MR. SCULLY: So even in the absence of a -- of these pilots, replacing the transformers would not be necessary, in your view, during the three-year rate period in order to continue to be able to provide reliable service. Is that fair?

MR. DESROSIERS: This is Adam. That's correct. Only if the transformers failed for another reason but not due to the overload concern.

MR. SCULLY: Thank you I just had one other question, and this goes to Rita I believe. You've answered this a couple of different times with respect to the battery of pilot, and what I've heard you say in response to a variety of questions is it's really important for us to get some information about how these things work, how they interact with the distribution system given that we think that this is the wave of the future and it is going to impact CMP's system. What I don't yet understand is if a third party not only designed, developed, and built it but owned it subject to your control, why could you not still obtain the same information that you think is important for the company to obtain?

MS. KING: This is Rita. We certainly could get that information. I liken it a little bit to giving somebody a fish versus teaching them how to fish. And in many instances, and I think I've answered this before, we're just looking at limited circumstances for CMP ownership. We absolutely think third-party ownership of storage is something that we're looking at today. We are forecasting having some storage interconnected onto our system, and, in the future, I think that there's going to be hybrid types of ownership models. One of the benefits, I think, to third-party ownership, and I know we're going to rebut this, but I'll just say it quickly to answer your question, is that when you think about third-party ownership, we do it through a contract. And some of our experience with our pilots in other jurisdictions indicates that we don't have as much flexibility. So while we may think today we have a good sense of what the use cases are and what we're looking to accomplish going forward, things change, right? Our system is dynamic and we may want to explore other types of use cases with that same asset. If you have to go back and open a contract, you know, you may be paying more for that same service, and we also need to think a little bit about that data, how it gets integrated into our system. And, you know, those are all the types of issues that today we don't have any historical experience with and, you know, we're trying to move forward and get some of that hands-on experience with.

MR. SCULLY: Okay. So with respect to your metaphor about the fish, I'm assuming that the value of learning to fish as opposed to being handed a fish is if you intend to do more fishing in the future. Is that fair?

MS. KING: This is Rita. I think that you want to do more fishing in the future, but you also can build on some of those lessons that you've learned with learning how to fish.

MR. SCULLY: Thank you. Thanks very much. Go ahead.

MR. BARTLETT: I had a couple of questions going back to the make-ready program. So I just want to -- part, I want to make sure I understand it, that what we're talking about with those make-ready charges, they're charges that are currently paid for by whoever's installing the charger. Is that right?

MR. BOCHENEK: Scott Bochenek. Yes, that's correct.

MR. BARTLETT: And so in this proposal, the theory is by essentially providing the credit for that or paying for that, it makes it easier for the owner to -- it makes it easier to get these installed, less expensive, and benefits the entire system?

MR. BOCHENEK: Scott Bochenek. Yes, that's correct. The idea is that by providing an incentive, developers or other customers will install more EV chargers than they would otherwise without the incentives.

MR. BARTLETT: And that provides a benefit by -- in terms of bringing on additional load to spread out costs and so forth, right?

MR. BOCHENEK: I can't confirm that. This is Scott Bochenek.

MS. ANCEL: This is Charlotte Ancel. That is correct, Chair Bartlett.

MR. BARTLETT: And so part of the justification for ratepayers paying for this more broadly is because if you bring on more load, you're spreading your fixed costs across more customers. Is that --

MS. ANCEL: So that is correct, Chair. There are certain limitations to that proposition. So, for example, if the electric vehicle chargers were placed in areas that were not compatible and made use of existing capacity on the grid, that principle could be eroded. But directionally, yes.

MR. BARTLETT: Is the program limited to those places where there is additional capacity or would it be available even in places where there weren't -- there wasn't that capacity?

MR. BOCHENEK: It would be available to -- this is Scott Bochenek. It would be available to all places.

MR. BARTLETT: And in terms of the cost recovery, I mean, you're talking about the capital tracker, and so this is -- you're essentially taking these costs and moving them into rate base. Is that right?

MR. BOCHENEK: This is Scott Bochenek. Yes, that's correct. Sorry, I just want to clarify that to the extent that the tracker -- I don't believe it would be in the rate base until the costs are spent and then begin to be recovered.

MR. BARTLETT: Right. And so I guess a question which may go to the policy panel is what's the justification for that, for moving these costs from the customer who is installing the charger to rate base? I understand the justification for the customers at large paying for it. What I don't understand is why that -- it would go into rate base as opposed to being directly expensed.

MS. ANCEL: I thank you for the clarification. The costs are -- the company is absorbing capital costs and putting them into rate base. So it's the capital cost of the in-front-of-the-meter line extension. And so they are given a capitalized treatment and, for that reason, included in rate base.

MR. BARTLETT: But if the customer pays for it, it wouldn't be going into rate base?

MS. ANCEL: That's correct because it's -- yes.

MR. BARTLETT: Would the -- does the company still think it would be worthwhile to provide these incentives if it was not going to rate base but instead were directly expensed? So as a pass through cost on the operating side.

MR. COHEN: This is Peter Cohen. In this instance, it wasn't -- if it wasn't a capital cost and was treated as expense, then it would be fine.

MR. BARTLETT: Okay, so the company feels it's worth going forward regardless?

MR. COHEN: Yeah, (indiscernible).

MR. BARTLETT: Did you explore it all whether some of these costs could be recovered through sort of the rate design for the charger itself? You know, for example, looking at recovering that cost through part of your fixed charge over ten years or something like that.

MS. ANCEL: We have not expressly considered that Chair Bartlett. We have seen that happen in other states, the idea being that the increased revenues from the chargers would cover their costs. That has not been -- as -- and Mr. Bochenek could speak to it further. As I understand it, that has not been a leading policy way to advance electric vehicles because of the decoupling of revenues and earnings in most states, meaning that there's a full reconciliation to the extent there's a differentiation in sales.

MR. BOCHENEK: This is Scott Bochenek. Just one other thing to point out is that generally, some of the usage on the publicly-available chargers by themselves might not account for all of the increased kilowatt hours from electric vehicles. We still think the majority of charging is going to be done at home and that's where a lot of the additional kilowatt hours would be would be used. But having chargers available publicly will help in, you know, people be comfortable with purchasing electric vehicles. And also just to point out that -- I think I have this number correct, that when we think about the make-ready concept broadly and what's happening in other places, there are, to my knowledge, 16 other states and -- that account for 27 utilities that are also implementing similar make-ready programs. And in many cases the incentives that are being offered would extend beyond just the utility-side and also for customer-side electrical infrastructure.

MR. BARTLETT: Thank you.

MR. SIMMONS: I wanted to follow that one up. Of those -- you said 27 -- 16 states, 27 utilities. Is that --

MR. BOCHENEK: Yeah, that's the number according to the Atlas EV Hub.

MR. SIMMONS: Okay. And do you have any idea how many of those 16 states have efficiency agencies that also incent EVs?

MR. BOCHENEK: I do not.

MR. SIMMONS: So I had a question about the electric school bus chargers. Your proposal's for 300 new school bus chargers. How was that projection developed?

MR. BOCHENEK: It was a based on a general assumption that roughly eight to ten percent of the school buses will turn over every year and that at the end of the three-year period, there would be 20 percent -- a potential for 20 percent of the current bus fleet to convert to electric buses. It's -- one other thing to that, I think it's an aggressive view that that many buses will electrify in the next three years, but we know that there's significant federal money that's being spent to help support school districts converting to electric buses. So we think that initially that's going to prompt a wave of interest, and by having these additional incentives, it'll help convince school districts to make that choice.

MR. SIMMONS: And did the federal funding that's available, did that inform the 300 electric school bus projection?

MR. BOCHENEK: It led us to believe that there will be a potential for a higher level adoption that would have -- than there would have been without the federal funding.

MR. SIMMONS: And are you aware that the EPA has awarded the first round of -- or the round of funding?

MR. BOCHENEK: Yes, I am.

MR. SIMMONS: And is the awards for the Maine school districts, does that change the projections at all?

MR. BOCHENEK: This is Scott Bochenek. It does not at this time.

MR. SIMMONS: Thank you.

MS. HEALY: Turning back to the batteries. Of the -- I guess I'll ask of the two panels sitting here right now. Is anyone familiar with Emera Maine's previously-proposed Hampden microgrid project, docket number 2017-0027?

MR. MADER: Jim Mader. only anecdotally.

MS. HEALY: Do you draw any distinctions between what Emera Maine had proposed in that case and the battery microgrid solutions that you've proposed here?

MR. MADER: I'd need --

MS. HEALY: I'm not asking for a legal analysis. I'll -- I'm just asking sort of from an operational perspective or --

MR. MADER: Yeah, unfortunately, I'd have to look at the proposal and say and then answer. I'm not, like, up to speed on what exactly they were doing with the -- with that project.

MS. HEALY: I'll just ask an ODR for whether CMP draws any distinctions between the two battery projects proposed here and the project proposed by a Emera Maine in docket number 2017-00027.

MR. DES ROSIERS: And, Nora, if I may, I'm assuming that the intention is on sort of an operational or the objectives of the project as opposed to regulatory or legal ratemaking and related issues that are a distinction --

MS. HEALY: That will, I'm sure, be briefed later. So, yes, from an operational perspective.

MR. DES ROSIERS: (Indiscernible) really lousy at answering data requests. So that's why I --

MR. BRYANT: So we're going to break for lunch in a couple of minutes. Let me ask parties, non -- parties who have not yet asked questions of this panel, meaning those parties who did not set aside time to ask questions, whether you believe so far you have any follow-up questions based on what you've been hearing. Let me turn to the OPA. You think you have any follow ups? Okay. I don't know who else has -- I think everybody else has asked a question. Let me ask just, Melissa Horne, whether you have any follow ups. I'm just trying to get a sense of how much time we have to take.

MS. HORNE: Thank you, Eric. I don't have any follow ups.

MR. BRYANT: Okay. So why don't you go ahead and ask (indiscernible) take a break?

MS. HEALY: Sure. This is sort of a one off, but in the written testimony on page 27, you talk about some of the grants that you award in partnership, I think, with UMaine, research-related grants of 75,000 to 150,000.

MR. SULLIVAN: This is Sean Sullivan. We haven't awarded those grants yet. Those are in the proposal for grant awards to collaborate with UMaine or other academic institutions for potential research studies (indiscernible) innovation pilots.

MS. HEALY: Okay, and how many of those grants are you proposing? I take it from the testimony a single grant would be between 75,000 and 150,000, but it references plural grants.

MR. SULLIVAN: That's accurate. It would be between 75 and $150,000. It would depend on the topic, the targeted solution that we're aiming at at that time. There may be multiple, but it wouldn't be more than two.

MS. HEALY: Wouldn't be more than two?

MR. SULLIVAN: Yeah.

MS. HEALY: Thanks.

MR. BRYANT: One more question before the break, and that comes from Faith as a follow up on questions that the Chairman asked.

MS. HUNTINGTON: This is a follow up to Chair Bartlett's question on the ratemaking treatment of the make-ready work incentives. If there were additional funding to be provided for EV support and that money were funneled through Efficiency Maine rather than per the company's proposal, would that accomplish the ratemaking goal of having these amounts be reflected as an expense rather than in rate base?

MR. COHEN: I think -- this is Peter Cohen. I believe that's correct.

MS. HUNTINGTON: Thank you.

MR. BRYANT: Okay. And you still have some more questions, right, Nora? So when we come back --

MS. HEALY: (Indiscernible).

MR. BRYANT: Okay. So let's plan on this panel being here when we come back. We'll let you know when we come in the room whether that's necessary. Following that, we'll move to the operations panel, then the vegetation management panel, then the revenue requirement panel. I think we're going to make it under the gun -- under the wire. It depends on -- you've all been very cooperative this morning based on what I said, I appreciate it. I think we're going to be okay, but let's stay efficient as we move through the afternoon.

MR. TURNER: Eric, quick on that note, I just wanted to say we reviewed our notes and are not going to have direct questions for the operations panel but reserve the right for follow up. So maybe that'll save some time.

MR. BRYANT: That's helpful. Thank you. Okay, let's come back at 1:30.

CONFERENCE RECESSED (November 10, 2022, 12:26 p.m.)

CONFERENCE RESUMED (November 10, 2022, 1:30 p.m.)

MR. BRYANT: We have determined that we're finished with our questions for the grid mod panel, and I polled the other parties just before we left for lunch and no one else had questions. So they have retired. They're still in the room, I believe. Or did they leave? Okay. Well, they're gone. They're gone. So we are going to start with the -- in the afternoon with the operations panel. They're now sitting in place, and I guess let's do what we've done. Starting with Adam, please state your name and go down the line.

MR. DESROSIERS: Adam Desrosiers, CMP.

MS. THERRIAULT: Kerri Therriault, CMP.

MR. THERRIAULT: Kevin Therriault, CMP.

MR. SADLER: Matt Sadler, CMP.

MR. COTA: Nathan Cota, CMP.

MS. MANENDE: Katie Manende, CMP.

MR. BROWN: Art Brown, CMP.

MR. BRYANT: Okay. And you are all under oath, correct? Hearing no reply, then, yes, you are all under oath. So let me start off here. This -- I know who's going to answer this because it's a question about automation. So in your testimony, it's -- just so you know, it's on page 29 and 30, but the company says it's starting in Alfred. And I know there were some questions on this either yesterday or day before, I think, from Michael Simmons. And if this has been answered, I apologize, but why is the company doing it by service area instead of by the areas that are the worst performing areas? And maybe they're the same, but can people generally address that question?

MR. DESROSIERS: I'll start and Joe can finish. This is Adam Desrosiers. So when we looked at how we would approach automation, we -- it was a couple of considerations that went in. The first one was starting with the worst performing service center which is Alfred.

MR. BRYANT: Okay.

The second piece was considering where we were planning to go with our energy control center and centralized operation, it made sense to do an entire service center at one time and convert that service center over to centralized control at the same time so that when the operator is operating in that service center from the ECC, it's consistent policy and practices across the service center, both from the ECC perspective and also from the field crew perspective.

MR. BRYANT: Okay. So in other words -- is the energy control center being set up in such a way that you can only add a division at a time?

MR. DESROSIERS: Not necessarily, but it would -- it's the most efficient model, in our opinion, to do so, when we transition to centralized control is to do it by service center so that you're being consistent with how you're operating the system in that service center. And it's not necessarily by circuit. It's more at the service center level.

MR. BRYANT: My understanding -- and did you have anything to add, Joe?

MR. PURINGTON: Thanks. This is Joe. So I would just add it's really about organizational change management as well, you know, because again, as I mentioned previously, the field right now has jurisdiction over these devices. So when they go out to restore and repair, if it's a SCADA control device, they'll call into the control center, the control center, will operate it for it -- for them. In the future, as you start to set up automation and you get enough penetration with automation, it's not just during an outage that the field dictates to the control center what's going to be opened or closed. The control center is dictating to the field what's open and closed. So it's just, from an organizational change management perspective, a lot easier to implement geographically by worst performing region from a system perspective.

MR. BRYANT: Okay, if -- thank you. If CMP -- according to the plan laid out in your testimony, when will -- and assuming you get the resources you need, when would the automation of your entire system be completed? The year 2030 sticks in my mind for some reason. I'm not sure why.

MR. DESROSIERS: Yeah, there's a data request on that. I believe it's 2031 is when we would be complete with the 2,000 or so devices that we proposed.

MR. BRYANT: Okay. When do you expect the energy control center to go into operation with regard to distribution?

MR. DESROSIERS: As early as next year is our plan. Our -- like, I think, Matt had described yesterday, we've already hired the operators that we would need to move to a centralized model. We're going to be working on building policies and procedures to support that centralized model. And as soon as we have enough automation in one division, we'll transition to that model in, for instance, in Alfred first.

MR. BRYANT: So the buildout of automation in Alfred is the trigger for converting for converting -- for how the ECC is going to be changed to distribution?

MR. DESROSIERS: In my opinion, it would make it much cleaner to have all that automation and do the transition at the same time. We could essentially do it earlier than that, and there might be areas where we choose to move to a centralized control earlier than having all the automation in place. But I think from the change management that Joe described and really changing the way we operate with the crews on a day-to-day basis, doing it once the automation is in place is makes the most sense.

MR. BRYANT: So a couple more questions on the ECC. And I'm going to be look -- Examiners 6-4 and Examiners 6-5. 6-4 we asked for whether CMP had done studies about the cost effectiveness of the OMS or the ECC. And the response was that based on the cost effectiveness of the investments in the ONS for CMP's -- OMS for CMP's affiliates, we expect there to be strategic shavings -- savings, etc. I didn't copy the whole answer in here. Does the answer only go to OMS or did you also answer for an ECC -- on an EC perspective?

MR. DESROSIERS: I'm not sure I completely understand the question.

MR. BRYANT: Okay. The data request asked for a cost-effectiveness analysis for OMS and for ECC. The answer, I believe, only refers to OMS and it refers to the cost effectiveness that your affiliates have claimed to have.

MR. SADLER: And that's in reference -- sorry, this is Matt. That's in reference to EXM 6-4?

MR. BRYANT: Examiners 6-4, yeah. Well, let me just ask this. Has the company done cost benefit or cost-effectiveness analysis that -- in writing that it can produce for the energy control center's transition to distribution?

MR. SADLER: You know, the transition to a centralized control model is really about reliability for the customers. You know, I think in the response we mentioned the reliability improvements we've seen in Spain, for example, and we also -- have some of our sister companies in the U.S. have a centralized control model. The efficiency gain that we mentioned, you know -- so centralized control is going to allow us to leverage the automation that we put in place and restore customers quicker and have a smaller -- less customers impacted per outage. And the efficiencies that we can gain are -- you know, we still have to have outages repaired in the field. We're going to have more automated devices that need to be maintained. So it's not going to provide a savings in field worker FTEs, but we do have seam and spectrum in our New York operating companies, and so we're able to leverage our New York resources for training for support repair of the system. We can take their procedures and modify them to work for us here in Maine. So those are the types of savings that we see from the implementation.

MR. BRYANT: Let me see if I understand your answer. First of all, there's no written study because you didn't say there was.

MR. SADLER: Correct. I do not have one.

MR. PURINGTON: Yeah, can I further elaborate?

MR. BRYANT: Well, let me follow up on what he said. So no written study. So -- and you also said that there won't be savings from a FTE point of view by moving the control to the control center. You still need the lineman out in the field.

MR. SADLER: That's correct.

MR. BRYANT: The other types of savings that I can think of, and I'm not an engineer, for such a change in how the company does its business would be quicker restoration of outages and better reliability.

MR. SADLER: Absolutely.

MR. BRYANT: But you have not studied that in any quantitative way. Instead you refer to your affiliates.

MR. SADLER: Yes, our affiliates have seen -- I'm sorry, this is Matt -- a substantial gain in reliability through the implementation of the system.

MR. BRYANT: Can --

MR. SADLER: Centralized control.

MR. BRYANT: Sorry. Can the company provide information from its affiliates, preferably from its affiliates' regulators that back up what you just said?

MR. SADLER: We -- so this is Matt. We did include in the data response that -- well, that's for automated grid recovery, but the combination of these systems that were implemented in Spain, yes, we can provide that that data I believe.

MR. BRYANT: So you reference Spain. You're not looking to any of your New York or Connecticut affiliates for this type of information?

MR. SADLER: Yes, we are. They do track it in New York.

MR. BRYANT: Okay. So let me see if I can get this data request -- this ODR right. Please provide any written reports or analysis from any CMP operating company affiliate, or at least about an operating company affiliate that shows the cost effectiveness of an energy control center such as -- or the changes to an energy controls energy such as CMP is proposing. And this is a reference to the -- Examiners 6-4, the response to that. And I guess I'll say the same thing. You can add this to that question for OMS and for the ECC. Make sure you've got that. Yeah? So, Joe, you wanted to add something?

MR. PURINGTON: Yeah, thanks. This is Joe again. So when we think about, you know, the model that we're moving to, there's really no choice. As the grid is evolving, all of this

DER penetration, if you're thinking about the technology that we're installing on the system, I -- you know, if you look at the -- if you were to compare the transmission control center and how it operates under ISO's umbrella to the distribution control center right now, what we have is a distribution dispatch center. The people in that dispatch center dispatch outages to crews. They do not run the system like a transmission control center operator. So the need is evolving from just being a dispatcher to having system knowledge and being able to operate the system. That's going to be absolutely critical as we kind of continue to see the changes to the grid with all of this penetration and technology. The efficiencies that we see from using a similar platform spectrum in New York to Maine is the implementation side. You know, learning from the mistakes or the challenges that occurred during the implementation in New York, we can learn from and not go through those same challenges in Maine. At the end of the day, when we're all on the same operating platform from an OMS perspective, and I think I've mentioned this before, but theoretically, we could have a New York operator helping manage outage restoration in Maine by giving crew assignments to Connecticut lineworkers. That's the real value in these centralized and enterprise solutions, and I've experienced that in my past. When we had a common platform at Eversource, we did the very same thing. So there's a lot of efficiencies like you mentioned in storm restoration, but, as Matt alluded to, you're going to have to still repair the outages. So there's not an FTE type of savings from the field side.

MR. BRYANT: Thank you.

MS. HEIMGARTNER: May I follow up on that? You mentioned you get to learn from perhaps the mistakes or growing pains from New York. How -- was the system installed and fully functional on time or were there delays? If you know.

MR. PURINGTON: Are you referring to New York?

MS. HEIMGARTNER: Yes.

MR. SADLER: This is Matt. I wasn't involved with the energy management implementation in New York, but as far as the outage management, I'd have to verify this, but if I recall correctly, I do believe there were some delays, just first time they had implemented that system.

MS. HEIMGARTNER: And you believe that with their knowledge and, you know, maybe their lessons learned, that Maine then can avoid some of these?

MR. SADLER: This is Matt again. So we have a (sic) operational smart grids group we call it, and they're the ones that are the technical experts on the system. So they are in charge of installing the system and maintaining it and making sure it has the proper data in it. And that group has some shared responsibilities among the opcos, and so we're using some of the same people that were in charge of implementing it in New York for Maine. And as a part of that, we talk about lessons learned from New York, and they've used some of the same programming. So they have taken those lessons learned and avoided the same mistakes in Maine.

MS. HEIMGARTNER: Thank you. That was helpful.

MR. DESROSIERS: And this is Adam Desrosiers. Just to add to that, at this point with the seam and spectrum implementation, we're weeks away from going live on the EMS side of that implementation and probably a month or two away from going live on the OMS side. So we've already been through a lot of those lessons learned. We're very focused on making sure every I is dotted and T is crossed before we go live on that implementation.

MR. BRYANT: One more question on the energy control center. Examiners 6-41, this relates to FERC Order 2222. So you state in your answer that FERC Order 2222, quote, will require local control centers to perform both day-ahead and real-time network analysis, etc., etc. Am I to read from this that the FERC Order 2222 requires a distribution utility to have a local control center?

MR. SADLER: And this is Matt. I don't have the -- a copy of the order right in front of me, but I don't -- I do not recall language about that.

MR. BRYANT: Is it your understanding that -- and this is a better way of asking actually. Do all distribution utilities have local control centers?

MR. PURINGTON: So this is Joe again. So depending on the size, they'll have -- a lot of them have dispatch centers for the smaller ones, like the co-ops. There wouldn't be a -- like, a control center function. Now within ISO's umbrella, there's six local control centers in New England.

MR. BRYANT: For transmission?

MR. PURINGTON: For transmission, yeah.

MR. BRYANT: Right. So what I'm taking then from your answers is that since CMP does have an ECC that it can convert to distribution, it sees that as the vehicle for meeting the requirements of FERC Order 2222. While there might be other ways, that's the way CMP sees it. Is that an accurate way to describe how you look at this?

MR. SADLER: This is Matt. Yes, that's accurate.

MR. BRYANT: Okay. NAMAG, shifting gears. So my understanding of the NAMAG -- and that's an acronym, N A M A G, organization is that it's an umbrella organization that utilities in the Northeast belong to for prioritizing and figuring out how crews from one area will be shifted to another depending on where a storm hits. Is that roughly accurate?

MS. THERRIAULT: This is Kerri. That is correct.

MR. BRYANT: Okay, thanks. So has CMP and Avangrid taken measures at NAMAG to address other utilities (indiscernible) are not in the NAMAG area and to reach out to those in times of need? Or do you exclusively work through NAMAG? I think I know the answer to this.

MS. THERRIAULT: We exclusively work through NAMAG.

MR. BRYANT: So --

MR. PURINGTON: And if I can add to that, Kerri, this is Joe again. So NAMAG will reach out to the other MAGs in the regions if they can't fulfill the request depending on the type of storm. If you if you're following the weather right now, Nicole's coming up the coast. So the southeastern MAG will not release any resources to NAMAG if there was a NAMAG request in that at this point. So it's really dependent, but to my comments I think it was yesterday or the day before, utilities won't release crews until they've passed -- the storm has passed them to ensure that they're in the clear for obvious reasons. This has been a discussion with utility CEOs across the nation, especially after EESIEEIS (phonetic) in 2018 and the impact that it had in some of the southern New England states. EEI understands this is a challenge, and I could characterize it as I think they're just as frustrated by the process because it works well after the storm has passed through, but before the pre-planning of the storm, it doesn't work so well unless you are clearly out of the path.

MR. SIMMONS: I had a follow up on the NAMAG.

MR. BRYANT: Go ahead.

MR. SIMMONS: So I've heard that, you know, the process is changing insofar as utilities don't, you know, release their crews and it's getting worse because there are external pressures on the utilities. Has there been any effort within the NAMAG organization to try to address all the work arounds that are occurring and try to -- instead of having an arms race essentially for personnel and storm crews, has there been any discussion in trying to remedy the problem in a way that, you know, keeps utilities from going out and getting crews way ahead of time, bringing them in from all over, circumventing the NAMAG process?

MR. PURINGTON: So I would say that NAMAG has had a lot of conversations around this issue. The external pressures that utilities are facing, it -- you know, there'll be no definitive improvement in the process because of those external pressures. So personally I don't see that issue going away anytime in the near future. And, again, as we talked about, when utilities are forced with penalties to restore power, that is -- just with timeframes that are not met, it just increases the arms race. And that's a great way of talking about it because we -- I used that a lot in my past. It's literally an arms race to get as many -- what you think you need ahead of time, and those decisions are being made earlier in the process. So EEI hasn't solved it.

MR. SIMMONS: And as far as, you know, affiliated company resources, are there outside external pressures in other states, such as New York, that limit your ability to use affiliate sources here in Maine?

MR. PURINGTON: I think I'd say there's a benefit to being part of an enterprise, you know, with New York and Connecticut. We -- you know, similar to Maine, we will not release crews from the Maine system until we are very confident that there'll be no impact and they're not needed. But, again, once we have those crews the affiliates own them, then we can work behind the scenes to get those crews allocated to the appropriate opco that needs the help. So it's definitely a benefit to have New York, Connecticut, and Maine part of the same family of companies.

MR. SIMMONS: All right, thank you.

MR. BRYANT: (Indiscernible) question about automation. If -- you said in Examiners 6-5 that distribution automation provides the highest expected reliability in France. (Indiscernible) that's the case, why has not CMP proposed more money for automation in this case and less for other items?

MR. DESROSIERS: This is Adam. I'll start. So really when we looked at especially what was forecasted in the this rate case, the -- starting in 2023, we were trying to find a balance between completing the projects that had started both from -- anything from a substation rebuild to a transformer replacement, also making sure we are focused on trying to get as much DLI done as we could working within the constraints of the budget but also making sure we're starting to invest in automation. There's definitely a desire to spend more on automation if we have an opportunity, and if a project, say in 2023, is delayed for one reason or another and that funding becomes available to move to automation, that will be the first project that we continue to move funding to to accelerate that implementation of automation.

MR. BRYANT: So if the Commission adopts the company's plan, the three-year rate plan, we shouldn't be surprised if, in certain years, we see more money going to automation and less to others?

MR. DESROSIERS: That's correct.

MR. BRYANT: (Indiscernible) during the (indiscernible)?

MR. DESROSIERS: Correct.

MR. BRYANT: Just a couple more. Examiners 6-30, Attachment 1. So this is about the DLI program and a year-by-year reporting on poles reported and poles completed. I assume by poles completed, you mean those are the -- when a problem was identified, completed means the problem was addressed?

MR. DESROSIERS: That's correct.

MR. BRYANT: Okay. So in column D should that -- that just says poles report. Should that say DLI1 poles reported? I was a little confused by that column heading.

MR. DESROSIERS: Yeah, it actually does in the cell.

It's just the text is not visible the printed version.

MR. BRYANT: So I want you to compare the numbers in column D with the numbers in column G. Column G's title, at least on my version, DLI1 poles completed. So this compares DLI poles identified with DLI -- sorry, DLI1 poles identified with DLI1 poles completed on a year-by-year basis. I'm wondering why those numbers don't match up since my understanding of DLI1 is that requires immediate attention, like within seven days. Some of those numbers are quite different.

MR. BROWN: This is Art Brown. The ones in the early years were a different priority, different timeline. One prior to 2016 was one year to complete, and the telephone set poles got into that. So there was some delay in getting those completed.

MR. BRYANT: So what you're saying then is in 2016 is when CMP adopted the current definition of DLI1 meaning --

MR. BROWN: Correct.

MR. BRYANT: -- now? And I see that there is, in fact, a shift. There are far more completions starting in 2016 than there are identifications. I take it you were playing catch up.

MR. BROWN: Yes.

MR. DESROSIERS: That's correct.

MS. HEALY: (Indiscernible) in 2014, were there are

269 DLI poles reported and 291 completed? Was that a catch up scenario?

MR. BROWN: Again, yes. The tel set was delayed so the ones completed could have been from prior years.

MR. DES ROSIERS: (Indiscernible) bring back fond memories of prior cases.

MR. SIMMONS: (Indiscernible) could set a picture of Chuck here for you if you'd like, Jared.

MR. BRYANT: (Indiscernible) me.

MS. HEALY: Or me.

MR. BRYANT: That's it for my questions. Does anyone else on staff --

MR. SIMMONS: I have a few. So the first one I have is on Examiners 6-16, Attachment 1, and I am looking at page number nine. And this is a presentation for the new service coordinator personnel request?

MS. THERRIAULT: This is Kerri. That is correct.

MR. SIMMONS: And if I'm looking at the organizational structure, it looks like the new positions that are being requested are in an effort to create a symmetry across all the all the different division -- I don't know if that's the right word, but division offices. Is that correct?

MS. THERRIAULT: That is correct. We have one per manager. So one per region.

MR. SIMMONS: And is -- what's the function of the coordinator? What is their role?

MS. THERRIAULT: So the service coordinator is the customer liaison between the customer and the business. So when a customer calls for a new service, that service coordinator will take control of that job. So they will contact the customer within 24 hours to start talking to them about the process. We've seen you've applied for new service. Here's the process. Here's the paperwork. This is what you'll need to do in order to move your job forward. They'll put a tickler in and they'll contact that customer again in two weeks just to make sure everything's going smooth. But that customer has a particular contact person that they can work with to take any confusion or questions out of their job. In addition to that, they are watching that job all the way through the process. So they're working with the business to remove any roadblocks or problems that may occur so that it doesn't slow down the process.

MR. SIMMONS: And how many new positions does the proposal seek to fill?

MS. THERRIAULT: So this is Kerri. We have already filled those positions. We filled them at the beginning of 2021.

MR. SIMMONS: And I guess just one follow up. Is -- are the -- all the new coordinator -- the new service requests, do they happen equally throughout divisions?

MS. THERRIAULT: No.

MR. SIMMONS: Okay. And so some of these divisions have more work than others?

MS. THERRIAULT: So they work as a team. So they will partner up and cover for one another or support one another if one workload is higher than another.

MR. SIMMONS: Okay, that's -- that was going to be my follow up is that there's -- they're covering multiple areas, but they're just located in a division office.

MS. THERRIAULT: Absolutely, yes.

MR. SIMMONS: I think I just had one other question that was going to be just a straight ODR regarding storms. So for each of the last five years, like, the date of the storm, the total incremental cost, the number of peak outages, the number of total customers affected, and the duration of the recovery. And that would be for tier one, tier two, tier three storms. So it doesn't matter which category.

MS. THERRIAULT: Okay, we can do that. Thank you.

MR. SIMMONS: That's all I had on this.

MR. DES ROSIERS: And, Michael, do you want them organized by tier one, tier two, or tier three or just in chronological order? Or it doesn't matter?

MR. SIMMONS: They can do that. So just chronological order is fine by me.

MS. TAYLOR: Just that -- the second qualifier -- the second category of information you wanted?

MR. SIMMONS: So --

MS. TAYLOR: You wanted the date of the storm and then --

MR. SIMMONS: Total incremental cost.

MS. TAYLOR: Okay, thank you.

MS. HEIMGARTNER: This is Greta. I'm headed back to automation again. We all come from different perspectives. In Examiners 006-005, Attachment 1, it lists out the service territories, number of circuits, and then the total count per year. And in looking at it, for 2023, has CMP already purchased those devices?

MR. DESROSIERS: This is Adam. We have already purchased, and, in most cases, we already have most of those on hand.

MS. HEIMGARTNER: And has the engineering been completed or is that still in the process?

MR. DESROSIERS: It is in process.

MS. HEIMGARTNER: And I notice that consistently each device was $100,000 which I would think would be reasonable. However, given the fact that you're doing a vast number of these, wouldn't efficiencies in later years help, you know, with the engineering because it will be so routine by then and, you know, even construction will be routine by then?

MR. DESROSIERS: Yeah, this is Adam. I would agree with you. Our average cost currently is about 100,000 per device. There is an opportunity to gain efficiencies there, although a lot of that 100,000 is the cost of the device. So likely with the efficiencies we will gain, the cost of the devices could increase. So I think that's why we approach this with the $100,000 average device. But if we're trending under and we have efficiencies, we will continue to add additional devices in each year as the budget allows.

MS. HEIMGARTNER: That's good because I'm in Fairfield so I don't -- I'm not getting it for a long time.

MR. PURINGTON: So this is Joe. You know, I'd also add you would think that the engineering would be similar, right, if you're installing a hundred. It's not. It's location dependent and it's how you coordinate the protection system settings with the other devices on that circuit, that is different. So the installation, depending on what you have to do, is obviously very similar, but the engineering behind it can be very different.

MS. HEIMGARTNER: Right, I'm aware of that. I actually did design work for 115 kV automation in my past. Last question on this one. I understand why you started at Alfred, but it does look like -- did you take that same philosophy of the second worst performing service territory and then just go down to the last? Because I know Skowhegan has a lot of outages.

MR. DESROSIERS: Yeah. So that was our initial approach. Alfred was our largest -- one of the largest districts, both customer account and number of circuits. And then we really worked our way up the coast. So, I mean, we did file an attachment to the electric ops testimony which showed about two-thirds of our customers our located within 20 miles of the coast. And that's -- with the storms and the frequency of storms, that's where we see the biggest impact from an automation perspective is starting in Alfred and working our way up the coast.

MS. HEIMGARTNER: That is what I figured. I (indiscernible).

MR. THERRIAULT: And this is Kevin. Just to add onto that, by starting south, we have greater tie capabilities in our more populated areas. So we'll see greater benefits in our southern Maine territories. As we move further north, we lose those tie capabilities.

MS. HEIMGARTNER: Great. Thank you very much. Should I ask my question from yesterday?

MR. BRYANT: Yes.

MS. HEIMGARTNER: Okay, this was on CIS. Examiners 009-80, Attachment 1.

MR. DESROSIERS: Yes, this is Adam.

MS. HEIMGARTNER: Do you have that up?

MR. DESROSIERS: Yeah.

MS. HEIMGARTNER: Okay. I was looking specifically at the asset conditions and the substation rebuilds and replacements. And in the year 2022, between the actuals, forecasts, and the variance, and -- why was there such a variance and please explain it?

MR. DESROSIERS: So I'll explain it, but I also want to point you towards EXM 009-002, Attachment 1. Page two of four also provides that variance description. So the variance you're seeing there is primarily related to the Forest Ave. substation rebuild. There were some costs that were originally charged to transmission that needed to be reallocated to distribution, and so that variance you're seeing has since gone away with our month-to-month actuals because of the move of that funding from transmission to distribution.

MS. HEIMGARTNER: Okay, similar question. In the planning studies for 2022, it doesn't appear that anything's been spent.

MR. DESROSIERS: You're referring to line 13?

MS. HEIMGARTNER: I would assume so. I only have a paper copy.

MR. DESROSIERS: Oh, okay. Yeah, I can -- I mean, it's -- looks like there was a budget of 100,000 with -- and a year-to-date variance of 100,000. This was a -- this table was originally based on what we call the eight plus four . So it was up to August actuals with four months of forecast. My assumption with that variance is the study work hadn't started prior to August. It was likely forecasted earlier in the year, but it hadn't started prior to August. Chris can probably confirm that.

MR. MORIN: This is Chris Morin. Have to double check if we spent any monies to date yet, but so far I'm assuming that variance is probably still there for the planning studies. We can confirm that if need be.

MS. HEIMGARTNER: I would like that confirmed. And my last question, still on this table, is under reliability, the transformer replacement. What was the reason for the variance?

MR. DESROSIERS: So likely that -- and let me refer to the other attachment, see if it's called out there, but I'm assuming it was likely due to a delay in transformer delivery. We could take that back as an ODR and confirm, but that line item is traditionally for purchase of replacement substation and spare transformers, and so my assumption is that's due to a transformer delivery delay.

MS. HEIMGARTNER: I would definitely like an ODR on that. I'm all set now, Eric.

MR. BRYANT: Anybody else on staff have questions for this panel? So let me turn to the OPA. Do you have any follow-up questions for this panel? No. CLF?

MR. TURNER: Hi, Eric, sorry, I had to switch to my phone. CLF does not have any questions.

MR. BRYANT: Okay. Any other parties participating remotely have questions for the operations panel? Okay, hearing nothing, we're done with operations, and we can move to vegetation management.

MR. DES ROSIERS: I'm assuming we're also then done with capital as well since it was just the hanging -- the holdover on --

MR. BRYANT: Correct.

MR. DESROSIERS: -- capital issue.

MR. BRYANT: Correct. The -- while this transition's taking place, I had a confidential question for the veg management panel which I now realize I can put in as an ODR. So I will do that. I'm obviously not going to state it now on the record. You'll see that coming, and I'll probably make it ODR 3-1 just since it's confidential and leave it out of set two. So you'll see that probably Monday or Tuesday.

MR. DES ROSIERS: Fine.

MR. BRYANT: Adam, are you just sticking around because you like this panel or -- I'm just -- not that you have to move. I'm not --

MR. DESROSIERS: I can't get enough of vegetation management. So I figured I'd hang out.

MR. BRYANT: Okay.

MR. DES ROSIERS: Joe's not in his seat. So somebody asked to, you know --

MR. BRYANT: So starting with Kerri, can I just have the three of you state your name and go down the row there?

MS. THERRIAULT: Kerri Therriault for CMP.

MS. MANENDE: Katie Manende, CMP.

MR. RANSOM: Bill Ransom, CMP.

MR. BRYANT: Thank you. And I remind the three of you you're under oath. Yeah, I just have a couple questions, and I'm not sure there are many more after me. The first one's a really easy one. Are the identities of your existing vegetation management contractors confidential?

MR. RANSOM: No, they aren't.

MR. BRYANT: So in other words, once you sign a contract with a vendor, that's not a -- that name is not confidential anymore?

MR. RANSOM: This is Bill. That's correct.

MR. BRYANT: What about the terms of the contract?

MR. RANSOM: This is Bill. That is confidential.

MR. BRYANT: Okay, right. My -- the confidential data request I just referenced will talk about your approach to vegetation management contracting that's coming up. I understand you will be issuing RFPs sometime in the next couple months. If you could turn to testimony, page 30. So this question is a ground-to-sky question. In that -- in the bottom paragraph on page 30 you talk about of the tree-related outages, approximately 95 percent resulted from tree or branch failures outside of the current trim spec. So do I take that to mean that if you were doing ground to sky, you'd still have 95 percent of the outages from outside the trim spec or does some of that 95 percent come from the canopy that would go away with ground to sky?

MS. MANENDE: So this is Katie. Some of that 95 percent would be eliminated with that ground to sky, by removing that overhead canopy.

MR. BRYANT: Based on the -- whatever past period you choose, can you give me a percentage of -- what percentage of that 95 percent comes from the portion that would be removed ground to sky? And it doesn't have to be an exact number, just, you know, 25 percent, 50 percent, 75 percent. What are we looking at?

MR. RANSOM: This is Bill. In our testimony we're estimating that -- and it's a conservative estimate -- 60 percent of these -- of this 95 percent is coming from the canopy.

MR. BRYANT: Okay, I must have missed that. Thank you.

MR. RANSOM: This is Bill. Actually that is in one of the attachments to a data request, that information is contained in there.

MR. BRYANT: Okay. Thanks. So that's a pretty big number. How does that compare to the amount -- the number of outages caused by hazard trees?

MR. RANSOM: This is Bill. So in our estimation, again, being very conservative, we're estimating that ten percent of the trees that we identify as hazards, ten percent of those would actually impact the line. It's a very conservative estimate. So if we're going to remove a hundred trees from the line, in our reliability improvements, we are not assuming that 100 percent of those trees would have hit the line. We're assuming that only ten of those hundred would hit the line. And that is our -- it's a conservative estimate based on past experience, but again, trying to be very conservative with what we're saying we can deliver in terms of benefits.

MR. BRYANT: So let me rephrase my question. Just as an order of magnitude, are there more outages caused from branches falling from the canopy that would be removed under the ground to sky than there are from hazard trees? Which contribute -- which causes more outages right now?

MS. MANENDE: So this is Katie. Anecdotally just in my eight years' experience here, I would say it's pretty even. Going out and doing all the outage investigations that I've done over my career, it's been a pretty good split of that overhead canopy versus trees from edge falling in. That being said, we discussed quite a bit in our testimony -- you know, the last couple days in testimony you've been hearing a lot of this forward thinking and planning ahead, and we know that with the effects of climate change and seeing more droughty conditions and also, vice versa, seeing those larger rain events and that higher saturation of soil as well as the onset of a number of tree pest diseases coming into the state, I do think that potential for a shift is there and you will start seeing more trees from the edge -- so outside of that right-of-way -- so coming to failure and falling in onto the conductors.

MR. BRYANT: Thank you. So the proposal for the ground to sky is on the three-phase lines, right?

MS. MANENDE: This is Katie. Yes, that's correct.

MR. BRYANT: And you have a proposal for stringing tree wire as well. My question is given -- let's assume the ground to sky is -- that the company goes and does that because it gets the funding. Would more of the tree wire be deployed on the single-phase lines than on the three phase because of the ground-to-sky improvements or has the company considered that?

MR. DESROSIERS: This is Adam. I guess I would look at it as, in most cases, traditionally today when we are installing tree wire on the three-phase portions of the circuits, it's being driven by, I guess, a few different items. It could be an addition of a DG. So we have to increase the conductor size. It could be additional load on the three-phase portion of the circuit. So, again, causing a loading issue resulting in the replacement of the conductor. If the ground to sky is purely being done to improve reliability, I would agree that there would necessarily not be a huge priority or focus to go and replace that conductor with tree wire. That would likely be driven by another component, whether it's load or distributed generation, in which case we would install tree wire in that case as our essentially new standard of conductor.

MR. BRYANT: So when the company needs to upgrade a line for a DG project, it just automatically uses tree wire?

MR. DESROSIERS: That's correct.

MR. BRYANT: What about in an area where there are no trees?

MR. DESROSIERS: From an efficiency perspective, we still install tree wire just as the crew is pulling the wire in, it's not efficient to switch between different reels of wire as they're stringing the conductor.

MR. BRYANT: Am I correct that the cost differential between bare wire and tree wire has reduced in recent years?

MR. DESROSIERS: That's correct.

MR. BRYANT: Is that one of the reasons for your previous answer?

MR. DESROSIERS: Correct.

MR. BRYANT: This is kind of along the lines we've just been talking about it, and maybe this is in a data response and I read it and forgot it, but for the ground-to-sky program, has the company put forth an estimate, a quantification, of the percentage of outages that will be produced in an average year because of the ground-to-sky program?

MS. MANENDE: This is Katie. Yes, we have. That information is in OPA 005-012.

MR. BRYANT: Thank you. But you've not attempted -- according to -- never mind.

MR. SIMMONS: I have a follow up on that --

MR. BRYANT: Go ahead.

MR. SIMMONS: -- OPA 05-012 attachment. And I think this will get at what you're getting at, Eric. So on page two of the attachment there's a chart with the two curves, and I believe it was briefly described the other day in response to a question. And I just wanted the company to kind of walk through the process of how those curves were developed.

MR. RANSOM: This is Bill. I can certainly do that. So if you -- I think it may be beneficial to start with page three of the chart and then you can see how we -- because this is basically a plotting of these numbers on this chart here on page three. So what the company did, we looked at the entire system for a given year and we took all the proximately 22,000 miles and we put them into a bucket. And those buckets were those that were trimmed within one year, those that were trimmed within two years, etc., etc. out to six years. Then we looked at the reliability data to see,, well, what is the customer impact by tree interruptions per mile for each bucket. Then when you when you look at the table, you'll see for those with a one-year age, their contribution to interruptions was 97,446. That's -- now that contribution is based on the customers interrupted per mile for that class of circuit. So if we're on a five-year cycle, you take the cost -- excuse me, the customers interrupted per mile by class times a constant 4,401 miles per year, and you will come up with the total amount of customers interrupted for a year by class. And that number is shown at the far right, 512,893.

We did the same analysis, but we extended it by adding six, and actually we did a trend line projection to see, well, what would the effect be for the sixth year. So when you look down to the six-year cycle estimated customers affected by circuit age grouping, you'll see that, for the cycle portion, the CI per mile, for the customers interrupted per mile, for years one, two, three, four, and five, it's the same because it's the same class.

But now we have a new class. That class are the customers that are now in year six. Their contribution for customers interrupted per mile is 33.12. We'll see that over there underneath the age six if you follow the CI per mile, customers interrupted, 33.1. So now we have the customers interrupted per class for years one through six. So now on a six-year cycle, the amount of miles on -- annually is six -- excuse me, 3,668. You take that amount of miles per year, take that, multiply it by the customers interrupted per mile by class, and you'll get the impact of moving from a five-year cycle to a six-year cycle. And the impact is going from 512,893 to 548,902. So there's a degradation in going from a five-year cycle to a six-year cycle. However, we reinvest the savings from doing that into the two programs, the ground to sky on three phase and the increased hazard tree removals, and you can see how for the hazard tree removal, we're looking for a decrease of 9,767 customers per bucket. Again, this is per circuit class. So annually you take that across all six classes and you come up with a reduction of 66,017 miles of interruption avoidance because of hazard tree. Similarly for ground to sky, there is a (sic) avoidance of customer interruption of 63,585. So the net reduction -- the net impact is an improvement, an overall reduction of 93,593. So that's based on our historical numbers and our projections based on our reliability from recent years.

MR. SIMMONS: And so the -- I would assume that under the -- or maybe or maybe since it's not changing, you didn't include it, but the other enhanced vegetation management programs such as hotspot and ancillary program, that's not accounted for in this case, right?

MR. RANSOM: There's certainly benefits to those programs, but they're not constant. These are kind of dispersed -- those programs are dispersed throughout the system.

MR. SIMMONS: Okay. So is one way to look at this -- okay, so the savings -- the customer interruption avoided for hazard removal, for example, is 66,000 over the course of the year?

MR. RANSOM: Correct.

MR. SIMMONS: And then the same would be 63,500 for the ground to sky?

MR. RANSOM: This is Bill. Correct.

MR. SIMMONS: Isn't that -- so would one way to measure the benefits of each of those programs or the contributions to SAIFI for both of those programs be to just divide it by the number of customers? Say you have the interruptions in total number of customers, and isn't that your SAIFI number?

MR. RANSOM: We may be saying the same thing. We're showing an impact -- we show an impact of each program.

MR. SIMMONS: Yeah, yes. Yes. So I guess the way I would say it is if we did that, we could see the contribution of that program to SAIFI.

MR. RANSOM: This is Bill. Absolutely, absolutely.

MR. SIMMONS: And so the total 93 point 5,000 (sic) interruptions would be the program change of your proposal to system reliability?

MR. RANSOM: This is Bill. That's correct. And you can convert that to a SAIFI number.

MR. SIMMONS: Okay. Thank you very much. That was very thorough and helpful. Thank you.

MR. BRYANT: I'm going to reference Examiners 4-12. That -- we were trying to get at the number of tree crews committed to CMP throughout this plan. And the answer is that you anticipate 120 to 130 crews will be working on the system, and then you provide a breakdown of what they'll be doing. How many crews does CMP deploy today?

MS. MANENDE: This is Katie. On average, we have approximately 110 tree crews on the system over all of the activities mentioned in that DR.

MR. BRYANT: Does the company anticipate any problems hiring or securing additional 10 to 20 crews in this job market?

MS. MANENDE: This is Katie. No, we do not.

MR. BRYANT: Why is that?

MS. MANENDE: And this is Katie. I believe it may -- it gets into confidential I think the way I would intend to answer that question.

MR. BRYANT: Okay.

MS. MCDONOUGH: Can I take a minute to huddle?

MR. BRYANT: Yeah, I'd like to avoid confidential because I don't think we have any for that. If we can avoid it --

MR. SIMMONS: Eric, maybe you can ask -- since you're already doing one confidential.

MR. BRYANT: No, I'm not doing that one. I'm going to turn that into an ODR.

MR. SIMMONS: No, right, it is ODR and maybe you can do this one is an ODR as well.

MR. DESROSIERS: This is Adam. So our plan is to diversify more the contractors we're using for veg M which will allow us to have those contractors more easily add labor and cruise when needed to get to that number.

MR. BRYANT: Can I ask what you mean by diversify more?

MR. DESROSIERS: Right now, the majority of our veg work is done by one company, a large majority which has caused labor availability issues on completing our circuit miles to date. So by adding additional contractors to the mix, we'll have the ability to get more crews from those contractors.

MR. BRYANT: So that's what gives you the confidence that you'll be able to secure the additional 10 to 20 crews?

MR. DESROSIERS: That's correct.

MR. BRYANT: Okay.

MR. SIMMONS: So I have a follow up on that same --

so for the list of items that the vegetation crews are responsible for, does the company have a prioritization as far as, you know, where those crews are working on those -- on that list of tasks?

MS. MANENDE: This is Katie. I thought I might get that question. So we mentioned in testimony that, you know, in the last cycle we've seen a significant increase in the level of capital work that vegetation management has done. So the DLI programs, the DG resiliency. So when those projects come on our radar, in addition to our new customer connections so those as well, we do prioritize that work in relation to our circuit mileage and the hotspot hazard work.

MR. SIMMONS: So when you say that work, you mean the capital work, the new connection, the DG?

MS. MANENDE: That is correct. This is Katie. And to date, we have always found the balance to accomplish all of that work, but I will not deny that it has been a challenge to do so under the current program we're at where we have -- we've historically had a limited pool of vendors to do that work.

MR. SIMMONS: Is there a further prioritization between the cycle work and the other ancillary trim programs?

MS. MANENDE: This is Katie. No, there is not.

MR. SIMMONS: And is it the same vendor that does both the cycle and the ancillary?

MS. MANENDE: This is Katie. Historically, yes, that's been correct. We on boarded some additional vendors this year to help with the capital as well as some of the hazard work.

MR. SIMMONS: Okay. Thank you..

MR. BRYANT: That's all I had. Anybody else on staff have further questions for this panel?

MR. SIMMONS: I have one or two. I think we -- we're going to talk, I guess, separately about the reliability calculator, but does the company use the calculator on its vegetation programming?

MS. MANENDE: Defer to Adam. This is Katie.

MR. DESROSIERS: We have not currently. This is Adam.

MR. SIMMONS: Okay. And the next question I had was in relation to Examiners 04-35. Make sure that number is right, sorry. Okay, yeah, so this is the question about the key performance indicators, and the company stated that there are performance metrics built into the contract. And I was wondering -- yes, maybe it's an ODR -- whether we can get kind of a -- the year-end 2021 API report from your vendor contractor, if that exists. Maybe I should ask that question first.

MS. MANENDE: So this is Katie. Can I first confirm if you're talking about Examiners 35 or 36? Because what you asked and then what you're referring to now almost sounds like it could be Examiners 36.

MR. SIMMONS: So there were going to be two questions. The first one was 35 related to the performance indicators that are built into the contract with the -- in the master service agreement as -- these include metrics on customer satisfaction here in specifications, timely completion of work, etc. Is that a report that either the vendor provides or the company manages?

MS. MANENDE: So this is Katie. There is no formal report, but we do track all of the information outlined, and those items are in that DR.

MR. SIMMONS: And so is there, like, an end-of-year report or a period that would show, like, say, 2021's performance?

MS. MANENDE: Can I have one second?

MR. SIMMONS: Or -- yeah.

MS. MANENDE: This is Katie. If you would like us to provide that data, we'll take an oral data request.

MR. SIMMONS: Yeah, let's do that. Provide the data referenced in Examiners 04-35 --

MS. TAYLOR: (Indiscernible) question number, 04 what?

MR. BRYANT: Thirty-five.

MR. SIMMONS: Thirty-five.

MS. TAYLOR: Thirty-five?

MR. SIMMONS: Yeah. Maybe you could explain how you -- how the -- how you track the data. Maybe that would help me understand what --

MS. MANENDE: Sure. So this is Katie. I think I can provide you an example based on what we have in the DR. So one of the metrics, for lack of a better word, is a crew-caused outage. So in the event a -- one of our contractors caused a crew-caused outage of any kind, it could be a service going to one singular customer, it could be a larger outage going to multiple customers, they are required to immediately notify the Central Maine Power district arborist plus the manager, so myself, and there's a form that we fill out to document that that occurrence has happened. So that would be one example.

MR. SIMMONS: And then you would just keep that in a spreadsheet or -- that this happened or you would just have a pile of forms?

MS. MANENDE: No, then it gets documented in a company online reporting system.

MR. SIMMONS: And then my next question was going to be about the company's own key performance indicators, that you mentioned you track the mileage production against weekly targets. And as an ODR, can I get maybe both the end of year 2021 and the to date 2022 reports?

MS. MANENDE: This is Katie. Yes, we can provide that.

MR. SIMMONS: Did you get that, Daya?

MR. DES ROSIERS: And, Michael, for the prior ODR, that was for 2021 data?

MR. SIMMONS: Yeah, I think I just want -- more than anything I just kind of want to see how it's --

MR. DES ROSIERS: -- organized?

MR. SIMMONS: -- and what's there, yeah. I think that's it for me, Eric.

MR. BRYANT: Anyone else on staff have questions for the vegetation management panel?

MR. SIMMONS: You know what, I do have one more. I'm sorry. Yesterday it was mentioned that one of the things that was happening was that -- in order to keep up on the cycle trim work is that there was more mechanized trimming. Is that correct?

MS. MANENDE: This is Katie. Yes, that is correct.

MR. SIMMONS: Is there any concern with the use of the mechanized or increased use of the mechanized trimming in regards to the kind of ongoing tree health associated with that?

MS. MANENDE: This is Katie. To answer your question, the answer to that is the contractors using that mechanized equipment still need to uphold the appropriate tree care standard. So just by using the mechanized equipment, they are not compromising tree health.

MR. SIMMONS: And what standards are they trimming to, what specification? Do you know?

MS. MANENDE: It's a tree care standard. That is something we could provide you in greater detail if you'd like to see that.

MR. SIMMONS: Yeah, that might be helpful. Thank you.

MS. MANENDE: And I guess -- excuse me, this is Katie. I'll add, you know, regardless of if the contractors are using a traditional bucket crew with a foreman in the bucket doing the trimming with equipment or if they're using a mechanized machine, my team of arborists, who are all licensed by the state of Maine, are going out and doing a quality audit on all of the work. So if they do notice anything that is not up to the appropriate standard, so is not a proper pruning cut or they believe a cut has been made that will compromise the health of that tree, we would take the appropriate measures to correct the issue.

MR. SIMMONS: And also along the lines of the -- kind of the ground-to-sky program, is there any industry data that would suggest that the ground-to-sky cutting has any detrimental impact on the health of the tree over time?

MS. MANENDE: This is Katie. What I would -- excuse me. What I would say to that is when we look at each individual tree that would be over, let's say, the three-phase infrastructure and we're looking at it and determining when we remove that overhead canopy, are we removing -- for a general rule of thumb -- 30 percent of that canopy. And if the answer is yes, at that point we are making the determination if we should be pruning that tree or if we should be looking to remove that tree in entirety.

MR. SIMMONS: And if it's a -- if it turns into a removal, how is that accounted for, you know, kind of the cost wise? Does it move out of the ground-to-sky program and becomes, you know, ancillary cost buckets that deals with whole tree removals or --

MS. MANENDE: I would say that would still fall under the ground to sky. This is Katie.

MR. SIMMONS: I'll finish.

MR. BRYANT: So we need your ODR. We didn't get that, the last one.

MR. SIMMONS: Provide the standard for the trim specification, yeah.

MS. HEALY: (Indiscernible) question. What happens with all the material that's trimmed and cut and how -- yeah, go ahead and answer that.

MS. MANENDE: Sure. This is Katie. So it's dependent on the situation. So there's a few things that we have to take in consideration when we're doing -- whether it's tree trimming or tree removal and then subsequently the material that results. So under our specifications for any trimming, whether it's cycle, hotspot, hazard, capital work, the tree branches that are under three inches in diameter, we will chip up and do one of two things with it. If we're in a rural area, so wood lot basically, we'll blow that material back into the woods so it can break down and return the nutrients to the environment. That's one reason we do it. Another reason we do it is with the onset of some of the tree pests and diseases into this state, it's preferential to leave that material on site so we don't further the spread of, in particular, I would say emerald ash borer because that is a huge concern and there's some state quarantines in effect restricting the movement of that material.

For your more urban landscapes, we will put those chips into the back of a chip fan, and then they are brought to a dump site and located there, again being mindful of any state quarantines. As far as any larger diameter wood, that is left on site per a timber slash law by the state of Maine. I used to know the number offhand, I don't anymore, but that material is left on site because it would be considered timber theft if we were to remove it otherwise because that is material legally owned by the customer. That being said, if a customer is adamant that they would like that material moved, we'll make appropriate accommodations to do so.

MS. HEALY: And so am I correct then there's no revenue that is generated from any of the trim or the logs that are --

MS. MANENDE: This is Katie. Yes, that's correct. There's no revenue generated.

MS. HEALY: -- sounds like there's not much potential for that given the state law.

MS. MANENDE: Yes, that's correct.

MS. HEALY: Thanks.

MS. HEIMGARTNER: This is not related to vegetation management. It goes back to yesterday. I'd forgotten I had this question. Adam, you were talking yesterday about supply chain -- we were doing supply chain issues and delays, and you mentioned you changed the species of pole that you now use. And you lowered your standards and it was the life expectancy, if I'm not mistaken. Am I correct on that?

MR. DESROSIERS: Yeah, we didn't -- this is Adam. We didn't necessarily change the species. We allowed additional species into the mix of allowed pole species.

MS. HEIMGARTNER: Okay. But the additional species, what is their life expectancy versus what is your normal species life expectancy?

MR. DESROSIERS: We'd have to take that as an ODR and go back and list the different species with the expected life expectancy because the treatment that gets put on those species can affect that too.

MS. HEIMGARTNER: And that is the reason why, though, there's some variance between the species, its life?

MR. DESROSIERS: Yeah. I mean, really it came down to -- the decision came down to there's certain species that we might have not allowed before might be more readily available on the market now. So there's a higher certainty that we're going to get the poles we order. So --

MS. HEIMGARTNER: Excellent. Daya, you get that?

MS. TAYLOR: Yes. So just for clarification, do you want all species or just the new species?

MS. HEIMGARTNER: I want all species.

MS. TAYLOR: Okay.

MR. DESROSIERS: Let me just clarify. So all species that we currently use and the expected life expectancy of those poles?

MS. HEIMGARTNER: Correct.

MS. HEALY: And do you want the new -- the expanded species to be separately highlighted or something so --

MS. HEIMGARTNER: Yes, separately highlight the new ones. Thank you, Nora.

MR. BRYANT: Okay, I think that's it from staff. Hearing nothing, does the OPA have any follow ups for this panel?

MR. LANDRY: Not so much a follow up. I've been looking at the questions I have for revenue requirement panel.

A couple relate to vegetation management so I thought it'd be better to ask them now.

MR. BRYANT: Okay. Yeah, that's a good idea. And then if they can't answer it --

MR. LANDRY: Right.

MR. BRYANT: - the next panel can.

MR. LANDRY: Really just a couple quick questions here. Was wondering when the -- whether the ECI studies that have been discussed in the case were prepared for this rate case or were they prepared for your operational purposes?

MR. RANSOM: This is Bill. So there's a couple of exhibits. One was to demonstrate the impact of ground to sky on some select circuits at CMP. So it wasn't done specific to the rate case, but it's very pertinent.

MR. LANDRY: I understand that. I was -- but I was trying to understand was the studies originally prepared so you could make decisions, management decisions, about how you wanted to deal with vegetation management or was it prepared to justify your decisions in the case?

MR. RANSOM: This is Bill. Good question. So we -- through our analysis, we had made a decision to perform ground-to-sky clearing on those circuits, those Jackman circuits. There was a desire to quantify the benefits from a third party, to have someone come in and give us an assessment of -- really it's an assessment of the benefit there, but this isn't the first time that we've had an interest in ground to sky. So it was looking at Jackman and how can we expand it. And, again, it just happens to be very pertinent to our case now.

MR. LANDRY: That's very helpful. Thank you. Do you know when was the cost -- what year the cost of that study was incurred?

MR. RANSOM: We may have -- this is Bill. We may have to take an ODR, but before we do, give us a minute.

MR. LANDRY: (Indiscernible) take it as an ODR. (Indiscernible) to get through today.

MR. RANSOM: This is Bill. So to be precise, we'll take an ODR, but the date on the documents, the work study update is dated in 2020. And that's -- if that's when it was delivered, that's when we paid for it. And the --

MR. LANDRY: That's when you paid for it?

MR. RANSOM: Yes, it would -- that's when we would have expensed it, but --

MR. LANDRY: That's fine.

MR. RANSOM: Okay.

MR. LANDRY: No ODR. Thank you very much. That's all.

MR. BRYANT: Any other party have any questions for this panel before they are dismissed? Hearing none, you're dismissed. Let's take our break, and when we come back, I believe we have one final panel, and they've been sitting here the whole time. Appreciate their patience. That would be the revenue requirement panel. Let's come back at 3:10.

CONFERENCE RECESSED (November 10, 2022, 2:54 p.m.)

CONFERENCE RESUMED (November 10, 2022, 3:11 p.m.)

MR. BRYANT: Welcome back. We now have the revenue requirement panel, and as I have with other panels, I'd like to ask you to identify yourself starting with Jacob and going -- moving down one by one.

(Indiscernible)

MR. BRYANT: Oh, sure. Okay, please identify yourself for the record.

MR. HURWITZ: Jacob Hurwitz, CMP.

MR. COHEN: Peter Cohen, Central Maine Power.

MR. MORAN: Kyle Moran, CMP.

MR. BRYANT: And are all three of you under oath? Okay, thank you. We'll start questioning with the OPA.

MR. LANDRY: Thank you. I'm Andrew Landry, the Deputy Public Advocate, and I'll be asking questions on behalf of our office. Actually, we've got them narrowed down quite a bit and this shouldn't take too long, but I'll start with, on page RRP-15 of the testimony beginning at line 13, you state that the company calculated the write-off factor based on five years to mitigate the effects of the COVID-19 pandemic on the calculation. However, in response to OPA 007-004 it states that the company has not identified any specific writeoffs that are directly related to COVID. I wondered if you could reconcile those two statements and --

MR. COHEN: So Peter Cohen. So what we were trying to do here is not -- we originally did the standard calculation which was three years, and it produced a number that was high. And so we chose to use five years which produced a lower expense and reduced the revenue requirement. And our justification was that we were not just capturing a COVID time. But you are correct, we could have had a higher revenue requirement if we had used those three years.

MR. BRYANT: And aside from just your subjective judgment, was there any other way in which you were able to determine that using the five years has effectively mitigated the impact of any COVID related --

MR. HURWITZ: There is some element of judgment. However, looking at the Table 4 on the page of the revenue requirement testimony that you pointed to -- and I'm sorry, this is Jacob -- you can see that the values in 2020 and 2021 are higher than 2017 to 2018. So we picked a five-year average and keep trying to be mindful of the approach taken in previous cases, but at the same time, as Peter said, mitigate the effects of (indiscernible) on the (indiscernible).

MR. LANDRY: Thanks. This may be an ODR. Well, I guess this is an ODR. We wondered if you'd be able to update Table 4 on page RRP-16 for '22 -- 2022 year-to-date information.

MR. HURWITZ: I'm sure that we could.

MR. LANDRY: Is seasonality in --

MS. TAYLOR: Just one second. Can I please have the page number reference again? You said RRP page --

MR. BRYANT: RRP-16.

MS. TAYLOR: Okay, thank you.

MR. LANDRY: Table 4.

MR. COHEN: So this is Peter. Yeah, there is seasonality to a degree. And so by selecting year to date, we would likely be providing you through September, possibly October. I think you'll minimize that to a degree. What might be more helpful is if we provided you the trailing 12 months so that you get a full 12 months of data even though two months of it is in 2021. That's how you would address these.

MR. LANDRY: Yeah, I agree. I'm just wondering whether we need both in order to --

MR. COHEN: We can do both. I mean, just one ODR, but we can do it both ways.

MR. LANDRY: Okay. Thank you.

MR. COHEN: So just add to that it'll be year to date 2022 and trailing 12 months.

MS. TAYLOR: Okay.

MR. LANDRY: Thank you. That's helpful.

MR. COHEN: Yeah.

MR. LANDRY: Now the next question I have for the next table is the SOP retainage shown on the same table, and we had asked a data request, OPA 007-004, why does the SOP retainage appear only in 2017. And you indicated -- well, you provided your response. I won't read it. If --and it was based on a stipulation and docket 2020-00228. If the stipulation was signed in 2021, why does the SOP retainage credit show up as a 2017 activity?

MR. HURWITZ: As described in the response that you pointed to, we made the change in 2018. However, I just wish to clarify that within Table 4, the only line in those first three lines that affects our calculation of uncollectable expense (indiscernible) revenue requirement purposes through the rate years is line number one regarding writeoffs.

MR. LANDRY: So the SOP retainage doesn't affect revenue requirements. Is that you're saying?

MR. HURWITZ: Correct. As you can see in the later lines of this (indiscernible) amount of writeoffs allocated to distribution which we compared our distribution revenues (indiscernible) write-off factor per dollar of revenue which we (indiscernible) apply for (indiscernible) which the SOP (indiscernible).

MR. LANDRY: Okay. Thank you.

MR. MORGAN: Drew, can I just interrupt for a quick minute?

MR. LANDRY: Sure.

MS. HEIMGARTNER: Hold on one second. When you speak, could you speak into the mic, please?

MR. MORGAN: Okay, this is Lafayette Morgan. Can you hear me?

MR. BRYANT: Yes.

MR. MORGAN: Okay. I understand when you say it does not affect the uncollectables, but if it were to have been recorded in 2021, would it?

MR. COHEN: This is Peter Cohen, Lafayette. No. So the calculation uses numbered row one, Table 4, writeoffs as the numerator. It does not use numbered row four which is net uncollectables. So the impact of the SOP retainage reclassification line, which is line three of Table 4, it doesn't matter what that is, the percentage would not change.

MR. LANDRY: Just to clarify, is that because the SOP retainage is collected through commodity?

MR. COHEN: That's the standard offer.

MR. LANDRY: Thank you. That's charged through the standard offer price?

MR. COHEN: Yes.

MR. LANDRY: Okay.

MR. MORGAN: Okay.

MR. COHEN: Yeah --

MR. MORGAN: (Indiscernible). Go ahead.

MR. COHEN: Not an ideal presentation here because it is -- not intentionally but is confusing a little bit.

MR. LANDRY: We're going to take a point off for that.

MR. COHEN: Yeah, well, it's Friday -- or it's your Friday anyways. It's not my Friday.

MR. LANDRY: Thank you. To move on to the next item which is you provided explanations -- in your response to OPA 007-013, you provided explanations for the change in number of employees. However, I think we requested the budgetary justification for the ejected -- for the projected hirings on Exhibit RRP-3. I wondered if, beside the explanation that you provided on our RRP page three, can you provide documentation that the projected increase in the number of employees shown has been approved?

MR. COHEN: So this is Peter. There is a degree of chicken and egg here, right? Because if we are proposing hiring in a rate case during a rate year that hasn't started, it won't start for another nine months, there wouldn't necessarily be approvals yet for those, you know, for the hiring because you wouldn't start recruiting nine months at best. Now the assumption that's used when we layer in incremental hiring isn't the beginning of the rate year. It's actually in the midpoint of the rate year. So we would be a year from when that would be rolling into revenue requirements.

That being said, I think it's prudent for us to go back because we're in our budgeting process right now and let's see and make sure that it's in the budget. Yeah, well, we'll confirm whether or not it's --

MR. BRYANT: So are you offering to answer an ODR to confirm that it's in the budget?

MR. COHEN: I'd like to. Yeah, I'd like to because I think that'll be helpful.

MR. BRYANT: So, I guess, Daya, I will ask an ODR for the company to confirm that the positions described on Exhibit RRP-3 at page three are in the budget.

MS. TAYLOR: Thank you.

MR. COHEN: You know, we --

MS. TAYLOR: I'm sorry one clarification. And would that be the 2023 budget?

MR. COHEN: Yeah.

MS. TAYLOR: Okay.

MR. COHEN: But I think in order to provide a most comprehensive, we're going to also provide the current staffing levels as well just so that you can kind of see the walking points.

MS. TAYLOR: Okay, thank you.

MR. LANDRY: The next one will be an ODR also. This -- but this does refer to OPA 007-021. And in that, you estimated a 63 percent O&M percentage and wondered if you could provide an explanation of how that was derived and provide a supporting calculation.

MR. HURWITZ: (Indiscernible) talked a lot -- this is Jacob. We've talked a lot over the last several days about the company's various capital-related proposals and how we've posed a significant increase in capital spending while it's relative to the previous case, and we felt it was appropriate to reflect that expectation in our capitalization ratio that we apply for payroll and pension and other benefit purposes.

MR. LANDRY: So did -- is this a judgment or is this -- was a calculation performed in order to come up with this number?

MR. COHEN: So the calculation that would typically be performed produced a result of -- this is Peter Cohen -- produced a percentage of 67 percent. So what that means is that 67 percent of labor expenses would have been expensed and then the remaining 33 percent would have been capitalized. Recognizing that the company has proposed a three-year rate plan where there is more capital spending than has occurred in the past, it stands to reason that history is not -- I mean, just like capital spending, you know, our contention on capital spending as well, history is not always the best indicator of the future. And in this case, because we have proposed, you know, an increase in capital, we reduced that to 63 percent, meaning that we are only recovering a revenue -- we're only expensing 63 percent. We're capitalizing the rest which, again, is reducing revenue requirement, the company's revenue requirement request. And it was a judgment call.

MR. LANDRY: Thank you.

MR. COHEN: Yes.

MR. LANDRY: That's helpful.

MR. SIMMONS: Before you move on, can I ask --

MR. LANDRY: Yeah, please.

MR. SIMMONS: Do you mind? So I appreciate the explanation because that's helpful. How do you account for the five categories that aren't in the revenue requirement at all and we're going to spend money and then true it up the following year? Does that affect your overhead calculations in a true up or what are you going to do with that?

MR. COHEN: So you can go pretty far down the path of this, right? And eventually it does turn into a circular reference if you are following me from an analytical perspective. The 63 percent was in recognition that we asked for 180, 190, and 200 million in capital spending in base rates, plus these programs was what generated the 63 percent. It is entirely possible that it won't be 63 percent, but that was kind of -- the -- what I felt -- this was my call to not go for 67. What I felt was it was too much, given what we were asking. It didn't pass a credibility test. So I took it down.

MR. SIMMONS: Okay. And part of that was to account for these unknown expenditures?

MR. COHEN: Yeah. I mean, if you really think about this, you have 180, 190, and 200 million, and then you have these other -- you know, these other carve outs or trackers depending on who's speaking and calling them. They're significant. They're not insignificant anyways, but they are dwarfed by the base. And so it's hard for that tip to be moving the iceberg around too much.

MR. SIMMONS: Okay. Thank you. I appreciate it. Thanks.

MR. LANDRY: Turning to your response to OPA eight dahs -- 008-007, you indicate in that response that you retained PricewaterhouseCoopers for this rate case for the purpose of projecting CMP's pension and OPEB expense during the rate years. Is it correct that PricewaterhouseCoopers calculated the amount that is -- that will be recorded for the rate years? I guess I'll restate that. Did they calculate the amount that was anticipated to be recorded -- expensed during that -- during the rate year?

MR. COHEN: Hi, this is Peter. So they are preparing an actuarial study that is used to forecast pension expense. That is what's used to set the revenue requirement, but it's a forecast. They don't -- this isn't something where you could say this is the run out of actuals because there are variables to -- that are assumed that -- you know, like the stock market.

And so just also, unlike other jurisdictions like New York, pension costs in Maine aren't reconciled. They don't have a reconciling mechanism. So the company is at risk for those variances here in Maine.

MR. LANDRY: So you mentioned that they're doing an actuarial study. When do you anticipate that that would be concluded?

MR. COHEN: It was used in our initial rate case filing.

MR. LANDRY: Oh, okay.

MR. COHEN: Yeah.

MR. LANDRY: I thought -- it sounded like it was --

MR. COHEN: There is something -- okay, so just -- we have indicated this in an ODR, but I think it's important since, you know -- there was a change in our pension program that does affect the cost that occurred after we ended -- we closed the window on the revenue requirement. And so we've said we're going to be providing an update with our rebuttal with that information. The good news is is that it's a reduction to the revenue requirement. The bad news is it's not, you know, a $50 million reduction, but it's a -- it's not going to get higher as a result of that. And we're going to add that to our rebuttal.

MR. LANDRY: So you'll update the pension and OPEB expense in your rebuttal to reflect the --

MR. COHEN: Yeah.

MR. LANDRY: -- those -- the changes to your --

MR. COHEN: Yeah, it was just there was a policy change that happened, and they had to evaluate it and analyze it and it wasn't done in time for the rate case, but it is now done. So we have to put it in because it's known.

MR. LANDRY: So --

MR. MORGAN: Drew, can I just interject? This is Lafayette. Is PWC a normal actuary?

MR. COHEN: Yes. This is Peter. Yes.

MR. MORGAN: Okay.

MR. MORGAN: All right, thank you.

MR. COHEN: You're welcome.

MR. LANDRY: So when was the cost of the study incurred by the company?

MR. HURWITZ: The engagement letter we provided with PWC was signed in February of this year. Not sure the precise timing of when we incurred the cost.

MR. LANDRY: Okay. But it was this year?

MR. HURWITZ: Yeah.

MR. LANDRY: And is this included in your rate case expenses that you're seeking recovery of?

MR. HURWITZ: Jacob. Yes.

MR. LANDRY: Thanks. Wrapping up pretty quickly here, I refer you to the response to Examiners 15-004. I don't know -- you indicate in your response that the continued increase in FERC account 588, miscellaneous distribution expenses, is related to increased interconnection related expenses as well as expenses related to COVID-19. Is it possible that you could provide us the amount that was specifically related to COVID-19?

MR. HURWITZ: This is Jacob. Yes, we could. I'm not prepared to do that now, but --

MR. LANDRY: Yeah, I understood. So as an ODR, and referencing the response to Examiners 015-004, please identify the portion of the increase in FERC account 588 that are related to COVID-19.

MS. TAYLOR: Thank you.

MR. LANDRY: And also, I think, referring to the same data request, why are interconnection-related expenses recorded in miscellaneous distribution expenses?

MR. COHEN: Drew, this is Peter. We're going to add the clarification of that in our ODR response, but just my opinion is that you incur expenses and then turn around and build the generator in two separate accounts, and then they net out. So this increase is just the increase of interconnection activity that there is an offset to. But we'll confirm that in our response.

MR. LANDRY: In the response to the prior --

MR. COHEN: That's correct.

MR. LANDRY: Yeah, okay.

MR. COHEN: Because it's addressing the --

MR. LANDRY: One more. Can you identify -- this might be an ODR. Can you identify the interconnection-related expenses that were recorded as miscellaneous distribution expenses?

MR. COHEN: So that's --

MR. LANDRY: Yeah.

MR. COHEN: Yeah.

MR. LANDRY: Okay. Is that the same ODR or --

MR. COHEN: Yeah, that's the -- the answer that I offered to add to the last ODR is that question. So we'll just leave it in that ODR.

MR. LANDRY: And that's all I have.

MR. BRYANT: Thank you, drew. Anybody on staff have any questions for this panel?

MS. SMITH: Hi, this is Lucretia. Can I ask a quick question?

MR. BRYANT: You can.

MS. SMITH: The PWC actuarial report, is that something that's done every year to set the pension cost -- pension and OPEB cost?

MR. COHEN: Hi, Lucretia. This is Peter. So there is work that is done by an actuary on our pension every year in order to settle it. This is unique because it's involves a projection. So I guess my answer to your question is, yes, an actuary does do work for the company every year, but it is a different analysis that is performed for a rate case.

MS. SMITH: Thanks. I was --

MR. COHEN: -- I'm sorry. Go ahead.

MS. SMITH: Go ahead. No, you go ahead, Peter. All right, that's it. Thank you.

MR. BRYANT: Does any other party --

MR. MORGAN: This is Lafayette.

MR. BRYANT: Oh, go ahead, Lafayette.

MR. MORGAN: Can I ask a follow up?

MR. BRYANT: Yes.

MR. MORGAN: With respect to the -- this is where I'm a little bit confused. I asked a few minutes ago if PWC was the normal actuary, and I think you said yes. So -- but then a minute ago, you seem to indicate that there's another actuary that does the costing, and I'm assuming those are the costs that are actually recorded.

MR. COHEN: Hi, Lafayette, this is Peter.

MR. MORGAN: -- ask you what --

MR. COHEN: Hi, Lafayette, this is Peter Cohen. I think I was confusing. I apologize. So what I believe Lucretia was asking is does Price Waterhouse do work for the company every year or just for rate cases? And I had indicated, yes, that they do work for us every year regarding our pension and OPEB plans. They also do this work. So they are our actuary that does both of those. So I wasn't being inconsistent with what I had said to you previously, but I think I garbled myself a little bit. So I apologize for that.

MR. MORGAN: Thank you. One more follow up. This is Lafayette. So in my thinking, whatever is projected in the studies that they've done here, when it's updated for the costs that are recorded on the -- for the financial purposes, is that a correct assumption?

MR. COHEN: So we are including in the future revenue requirement estimates of pension and OPEB expenses that were produced using the actuarial studies that PWC prepared for the company beginning in February of 2022. The actual costs, as they occur, so they have not yet been finalized for 2022, that's what hits the books. In Maine for Central Maine Power, we are not -- our rate plan does not provide for reconciliation of pension and OPEB costs which is dissimilar to other jurisdictions in New England and not something that we've requested in this case. So we are left with -- any difference between actual and the forecast used to set rates is not reconciled. Does that answer your question?

MR. MORGAN: Somewhat. For ratemaking purposes, are we not using the accrual estimate or are we using the cash basis?

MR. COHEN: Hi, Lafayette, I just wanted to make --

this is Peter -- I just wanted to make sure I have my terminology correct. We're using the forecast information?

MR. MORGAN: Which is the equivalent of the accrual amount. I mean, obviously it would be the -- I assume that the study would then be updated going forward before you record what actually hits the books.

MR. COHEN: Hi, that's -- so it is using the accrual. This reference for you to see the calculation is workpaper RRP-3-8. And to the extent that information before the end of this case is available to update this -- and I had already mentioned that we are doing an update to this number in rebuttal because of a known change to the plan -- then we would do that update. The company would also be amenable -- if the OPA wanted to reconcile pension and OPEB costs, we would be amenable to that, but I don't know that that would be something you would be proposing.

MR. MORGAN: This is Lafayette. Another follow up. So during the test year, was there an amount recorded on the books for fees paid to PWC for doing this actuarial work?

MR. COHEN: So PWC does more than just the rate case actuarial studies for the company. So there were costs associated with work they do every year independent of these costs to perform a rate case study.

MR. MORGAN: I'm not sure if you answered. So I'm sorry, I'm just trying to make sure I understand. Every year there's some actuarial report that provides the amount for the company to accrue for pensions and OPEB, and the actuarial company gets paid a fee for doing that work. And so I'm wondering if those costs are not included in the cost of service.

MR. HURWITZ: This is Jacob. I'll take a crack at answering your question. So as Peter described, PWC routinely does work for the company, including producing actuarial reports that we use to book the costs, book expenses in that year. However, for this rate case, they've prepared a special unusual report, for which we've produced the engagement letter, that we used to forecast pension and OPEB expense for rate case purposes. You'll see the revenue requirement workpaper Peter pointed us to, Exhibit RRP-3-8, pension and OPEB expense, includes amounts going out five years into the future. So we're not booking any expense for 2026 this year obviously. So it's -- I think we're getting a little bit confused by your question, but please let us know if that doesn't address it.

MR. MORGAN: Your response was helpful. Thank you.

MR. BRYANT: Lucretia, do you have a follow up?

MS. SMITH: I do. Just out of -- is PWC your auditor for your financial statements or is there another -- do you have another audit firm that does your audits?

MR. COHEN: Lucretia, this is -- oh, this is Peter, Lucretia. I have to be honest. In regulatory I don't know who it is right now. Your public accounting firm rotates not every year but there is a regular rotation that occurs, and I don't know that it is PWC right now or not. I have to say I'll have to take an ODR to tell you who it is because I don't have anybody here -- this is the curse of being the last panel is I don't have many people I can look to help me answer that question, but I'll have to take an ODR.

MS. SMITH: That's all right. That's not necessary. I can find out by looking at the reports that were filed so --

MR. COHEN: Oh, okay. It might be KPMG Kyle is saying so --

MS. SMITH: That sounds like -- I remember seeing a printout with their name, but it could be somebody else but --

MR. COHEN: There is a tendency to have it change. I think it's every three years or so, but -- yeah.

MS. SMITH: Thank you. I'm all set, Eric.

MR. BRYANT: Okay. Thank you, Lucretia. The OPA is done?

MR. LANDRY: Yes, thank you.

MR. BRYANT: Okay. Any questions from any other parties for the revenue requirement panel? Hearing none --

MR. SIMMONS: Were you going to go down your list of questions on Power Tax, Eric?

MR. BRYANT: I'm going to submit those as --

MR. SIMMONS: As ODRs --

MR. BRYANT: -- ODR set four. Thanks for reminding me. No, never learned about Power Tax and I don't intend to.

MR. COHEN: I'm going to say --

MR. BRYANT: No offense, Peter.

MR. COHEN: I sure you're not going to ask me those questions. He's retired.

MR. BRYANT: Oh, okay.

MS. SMITH: I have to say, Peter, I was just as frightened as you might have been when he mentioned Power Tax.

MR. COHEN: That's right, Lucretia. We did live that one, didn't we?

MS. SMITH: Yes.

MR. BRYANT: Okay. So the regulatory requirements panel is excused. Thank you for your responses. And I believe we are done with the questioning in the technical conference. Nora wants to put a note on the record about the meeting coming up.

MS. HEALY: Yes, I think so people know, the meeting that we had discussed a between CMP and staff to work through the -- CMP's reliability tool or calculator we're scheduling for next Tuesday at 9:30. It's going to be conducted by Teams. It will be recorded, and, of course, any party that wants to attend, please let us know. Drew and Susan, I've sent you an invite already, including Bill, but have not -- I'll wait. If other parties want to attend, please let me know and we'll include you in the invite.

MR. BRYANT: And we'll be issuing a procedural order as well. So let's -- can we go off the record?

MR. DES ROSIERS: Well, just one -- it can be off the record. It's fine.

MR. BRYANT: Maybe just put this on the record. The responses to DER set two, which is -- I think there are now 50 questions -- no, 49 questions, and my one question in ODR three will be due November 22nd. And so with that, let's go off the record.

CONFERENCE ADJOURNED (November 10, 2022, 3:46 p.m.)

C E R T I F I C A T E

I hereby certify that this is a true and accurate transcript of the proceedings which have been electronically recorded in this matter on the aforementioned hearing date.

D. Noelle Forrest

D. Noelle Forrest, Transcriber